2024 STATE OF REGIONAL TRANSMISSION PLANNING

AN INTERIM TRANSMISSION PLANNING AND DEVELOPMENT REPORT CARD

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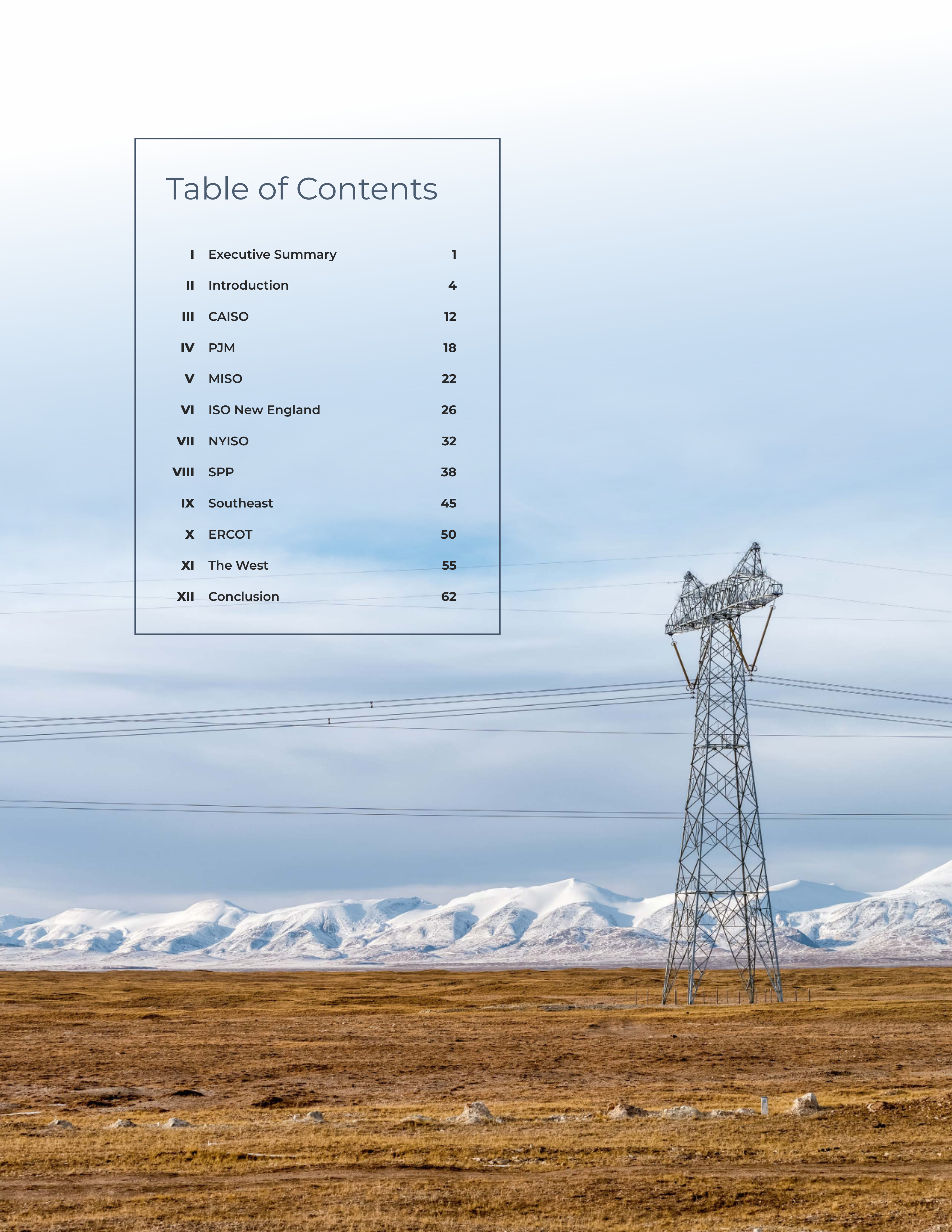
GridStrategies

Americans for a Clean Energy Grid

This report was sponsored by Americans for a Clean Energy Grid (ACEG). ACEG is a non-profit broad-based public interest advocacy coalition focused on the need to expand, integrate, and modernize the North American high-capacity grid.

OCTOBER 2024



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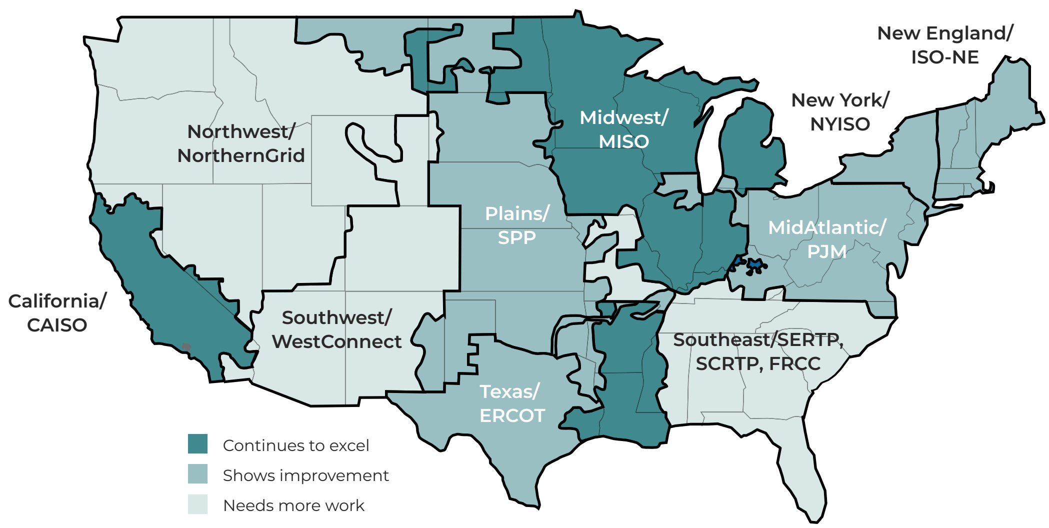
I. Executive Summary

A year after publishing the initial transmission planning and development report card, this interim review of regional transmission planning processes provides a qualitative update of planning practices and reforms that are underway. We find that across the country, several regions have initiated steps to reform their long-term regional transmission planning processes. Many of those reforms are promising improvements. However, despite the promise, many of these reforms are also in early stages of implementation and it is not clear what the final outcome will be or how it will impact actual transmission development. In regions where planning reforms have not been initiated, that may change going into 2025 as transmission planners are currently required to submit compliance plans/tariffs with the long-term regional transmission planning requirements in the Federal Energy Regulatory Commission's (FERC) Order No. 1920 by June 2025.

FIGURE 1 Progress on Regional Transmission Planning Since 2023 Report Card



Two regions, the Southwest Power Pool (SPP) and the California Independent System Operator (CAISO), are pursuing reforms to more fully integrate or harmonize transmission planning and generation interconnection processes, which is encouraged but not required by Order No. 1920. SPP's reforms are called the Consolidated Planning Process (CPP). The next step in the CPP is to conduct transition studies which will establish the foundation to move away from separate generation interconnection and transmission planning studies into a single planning process. SPP expects to file tariff reforms for the CPP in coordination with its Order No. 1920 compliance. SPP also produced a historic annual transmission plan to enable additional load and generation expansion while also enhancing system resiliency during extreme weather events. CAISO continues to make improvements to harmonize planning and interconnection processes. CAISO's *2023-2024 Transmission Plan* built on the previous zonal approach to coordinate transmission planning, interconnection study prioritization, and state resource procurement.

New York has also established an integrated local transmission planning process called the Consolidated Grid Planning Process (CGPP). The CGPP is intended to align local utility transmission system planning and development with New York's climate and energy laws, and NYISO's bulk transmission planning and generator interconnection processes.

Two regions, ISO-NE and PJM, are taking steps to develop and implement improved long-term regional transmission planning. ISO-NE is further along with its process. The region conducted a state-led, proactive, multi-value transmission study to evaluate transmission needs in 2050 required to meet state law, and received tariff approval from FERC for its long-term transmission planning rules that enable the states to move forward with transmission investments in connection with the study. PJM, working with interested parties, also proposed a new Long-Term Regional Transmission Planning process, which would have included the development of three scenarios and more proactive generation and retirement forecasts. These reforms have been delayed, and PJM is now wrapping these changes into its Order No. 1920 compliance efforts.

Several regional planning entities, including the Southwest Power Pool (SPP) and Electric Reliability Council of Texas (ERCOT), made changes to better evaluate the impacts of extreme weather within transmission planning. SPP incorporated two extreme weather scenarios, based on Winter Storms Uri and Elliott, into its 2024 Integrated Transmission Plan, but this analysis was limited to a specific subregion in its footprint. Texas grid planners are required by state law to better account for extreme weather and are expected to release a report at the end of 2024 evaluating transmission needs from two extreme weather scenarios—a hurricane and extreme cold. WestConnect—a regional planning entity in the southwest United States—has also added an informational-only extreme cold weather scenario to its upcoming transmission plan.

Order No. 1920 went into effect in August 2024 and transmission planning entities are still in the early stages of compliance. Current compliance deadlines are June 2025 for long-term regional transmission planning compliance and August 2025 for interregional compliance. However, MISO has stated they will be requesting a year extension on compliance. A few regional planning entities, including NYISO and PJM, have started to seek input from interested parties on how the region could best comply with the rule. One region, ISO-NE, has formally initiated the State Engagement Period required by Order No. 1920 to allow for State cost allocation deliberations. In addition, NorthernGrid and CAISO have announced that they intend to commence their State Engagement Periods on November 1, 2024. In the Southeast, SCRTP and SERTP announced they will be merging to comply with Order No. 1920. For regions that have developed or are developing transmission planning reforms, it is uncertain how the new Order No. 1920 long-term regional transmission planning rules may interact with ongoing reforms, or whether new regional initiatives will be deemed by FERC to be in compliance with Order No. 1920.

II. Introduction

A. FERC Order No. 1920 requires transmission planning best practices

Our 2023 regional transmission planning and development report discussed FERC's ongoing efforts to reform long-term regional transmission planning. In May 2024, FERC issued its final rule, Order No. 1920, which required the adoption of transmission planning consistent with the best practices identified and evaluated in ACEG's 2023 report card. Order No. 1920 requires that transmission providers participate in a regional transmission planning process that is "sufficiently long term, forward-looking, and comprehensive" to identify Long-Term Transmission Needs.[1]

1 Order No. 1920, Building for the Future Through Electric Regional Transmission Planning and Cost Allocation, FERC 187 FERC ¶ 61,068 P 224, (May 13, 2024) (hereinafter Order No. 1920).

Order No. 1920 requires planners to develop a regional transmission plan at least every five years using a 20-year planning horizon.[2] The plan must use best available data to develop at least three scenarios that incorporate seven different inputs including:

> "(1) federal, federally-recognized Tribal, state, and local laws and regulations affecting the resource mix and demand;
>
> (2) federal, federally-recognized Tribal, state, and local laws and regulations on decarbonization and electrification;
>
> (3) state-approved integrated resource plans and expected supply obligations for load-serving entities;
>
> (4) trends in fuel costs and in the cost, performance, and availability of generation, electric storage resources, and building and transportation electrification technologies;
>
> (5) resource retirements;
>
> (6) generator interconnection requests and withdrawals; and
>
> (7) utility and corporate commitments and federal, federally-recognized Tribal, state, and local policy goals that affect Long-Term Transmission Needs."[3]

Once the scenarios are developed, to help identify regional transmission facilities or portfolios that will efficiently and cost-effectively address long-term transmission needs, planners must evaluate seven economic and reliability benefits including:

> "(1) avoided or deferred reliability transmission facilities and aging infrastructure replacement;
>
> (2) a benefit that can be characterized and measured as either reduced loss of load probability or reduced planning reserve margin;
>
> (3) production cost savings;
>
> (4) reduced transmission energy losses;
>
> (5) reduced congestion due to transmission outages;
>
> (6) mitigation of extreme weather events and unexpected system conditions; and
>
> (7) capacity cost benefits from reduced peak energy losses."[4]

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2 *Id.* at P 248.

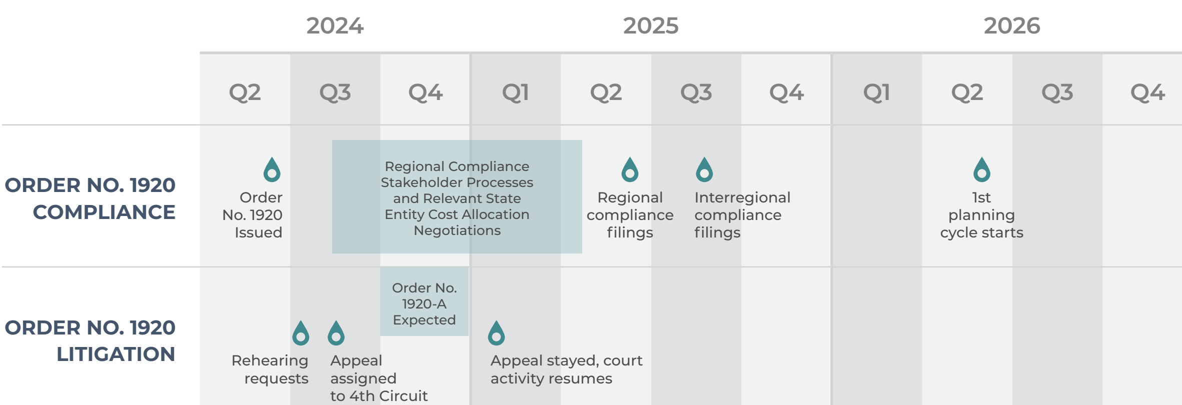
3 *Id.* at P 248, 409.

4 *Id.* at P 720.

As a part of evaluating regional projects or portfolios, planners are also supposed to consider the use of Alternative Transmission Technologies, such as Dynamic Line Ratings (DLR), Advanced Power Flow Control (APFC) devices, transmission switching, and advanced conductors, as well as opportunities to "right-size" the replacement of aging transmission lines.[5]

Once the planners identify a common set of benefits for proposed regional transmission projects or portfolios of projects, a project selection process occurs and then the costs of the selected projects are allocated across members of the region based on who benefits from projects. Order No. 1920 also allows states or interconnection customers the opportunity to fund all, or a portion, of the cost of long-term regional transmission facilities that otherwise would not meet the transmission provider's selection criteria.[6]

FIGURE 2 Order No. 1920 Implementation Timeline



Order No. 1920 requires regions or transmission providers to comply with the long-term regional transmission planning requirements by June 2025, and the interregional planning requirements by August 2025. However, Order No. 1920 has been challenged in court and there may be some regions that wait for the courts to resolve the challenges before complying. Historically, the electric industry has not waited to comply with FERC orders, and generally, compliance filings were submitted while courts reviewed challenges, but there is no guarantee those tendencies will persist. FERC is also likely to issue a follow-up to Order No. 1920 which will address clarifications and requests for rehearing. This addi-

5 *Id.* at P 1198, 1677. The term "right-size" means modifying transmission facilities to more efficiently or cost-effectively address regional transmission needs instead of simply replacing aging infrastructure as it reaches the end of its useful life. *See id*. at P 1566.

6 *Id.* at P 904-1062, 1291-1523.

tional order may also delay compliance with Order No. 1920. For example, for Order No. 2023, FERC gave transmission planners an additional 30 days to update their compliance filings after issuing Order No. 2023-A. Once transmission providers have filed Order No. 1920 compliant tariff changes that are accepted by FERC, they will have up to a year, approximately June 2026, to begin their new long-term regional planning processes.

Order No. 1920 requirements will ideally focus long-term regional planning efforts on the development of and investment in multi-value high-capacity transmission lines that will provide the most benefits to consumers and shift planning processes and investment away from the more inefficient just-in-time and incremental planning approaches that continue to be common today.

B. The need for transmission remains clear

The reforms underway are needed as it is clear the U.S. must develop new transmission capacity in the next few decades. Since the 2023 report card release, new studies and updates continue to demonstrate the need for new transmission capacity in order to affordably maintain reliability and meet demand for which forecasts have generally grown over the course of 2024.

In October 2023, the U.S. Department of Energy (DOE) released its *National Transmission Needs Study* which found the U.S. will need to more than double intra-regional transmission capacity and quadruple interregional transmission capacity by 2035.[7] In October 2024, DOE's *National Transmission Planning Study* found a similar need to double or triple regional transmission capacity and quadruple interregional transmission capacity. This expansion would provide $1.60-1.80 in benefits for every dollar spent on transmission.[8] However, FERC's reports on transmission development show that high-capacity transmission development is lagging. In 2023, less than 60 miles of new high-capacity transmission lines were built, and so far 2024 does not have a much better outlook, with only 125 miles of high-capacity transmission being put in service—all of which can be attributed to a single line.[9] In addition, nationwide transmission congestion costs amounted to $11.5 billion in 2023, remaining elevated compared to the previous decade, demonstrating that the existing transmission grid cannot deliver the lowest-cost electricity

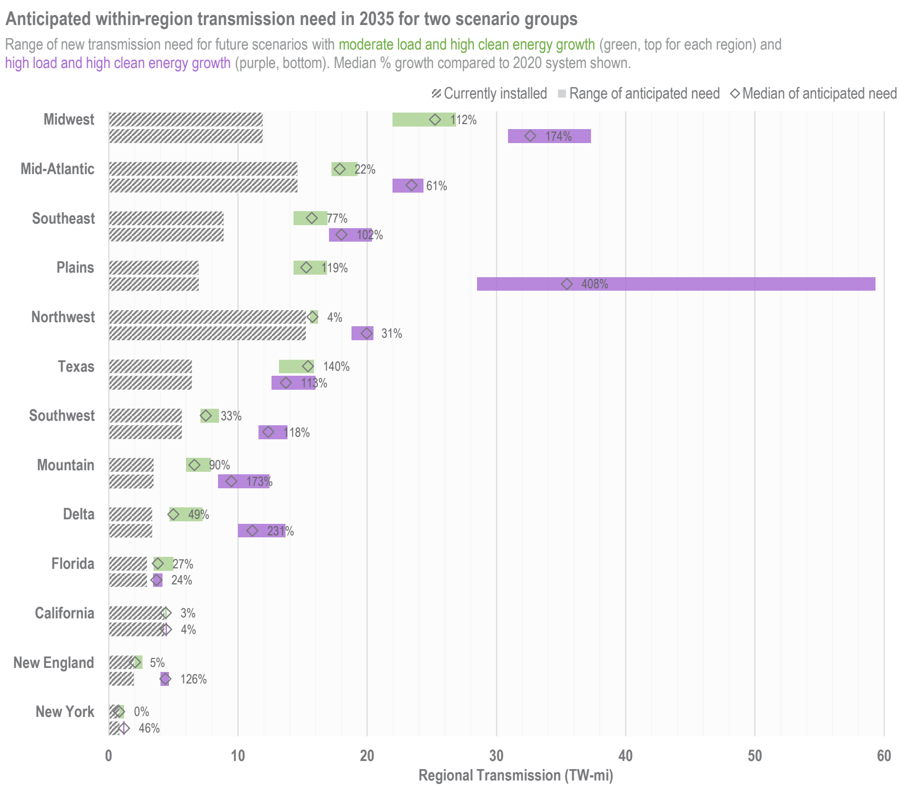
7 U.S. Department of Energy (DOE), *National Transmission Needs Study*, October 2023, at vii-xi, https://www.energy.gov/sites/default/files/2023-12/National%20Transmission%20Needs%20Study%20-%20Final_2023.12.1.pdf (hereinafter *National Transmission Needs Study*).

8 U.S. Department of Energy Grid Deployment Office (GDO), *National Transmission Planning Study Executive Summary,* October 2024, https://www.energy.gov/gdo/national-transmission-planning-study (hereinafter *National Transmission Planning Study*).

9 ACEG and Grid Strategies, *Fewer New Miles: The US Transmission Grid in the 2020s*, July 2024, https://cleanenergygrid.org/wp-content/uploads/2024/07/GS_ACEG-Fewer-New-Miles-Report-July-2024.pdf.

generation to consumers.[10] The Lawrence Berkeley National Laboratory also released an update to their value of transmission study finding that, despite a mild year of weather and decreasing natural gas prices, there were still interregional transmission lines that would have provided significant benefits to consumers.[11]

FIGURE 3 DOE ***National Transmission Needs Study*** **intra-regional transmission needs in 2035.**[12]



The United States is also beginning a transition from an era of little-to-no load growth, to an era with potentially significant load growth. A 2023 Grid Strategies study found that grid planners doubled their forecasted load growth from the 2022 to 2023 forecasts. The main drivers of this large load growth are new manufacturing, industrial, and data center facilities, and expanding transmission capacity will be critical to meeting these needs.[13]

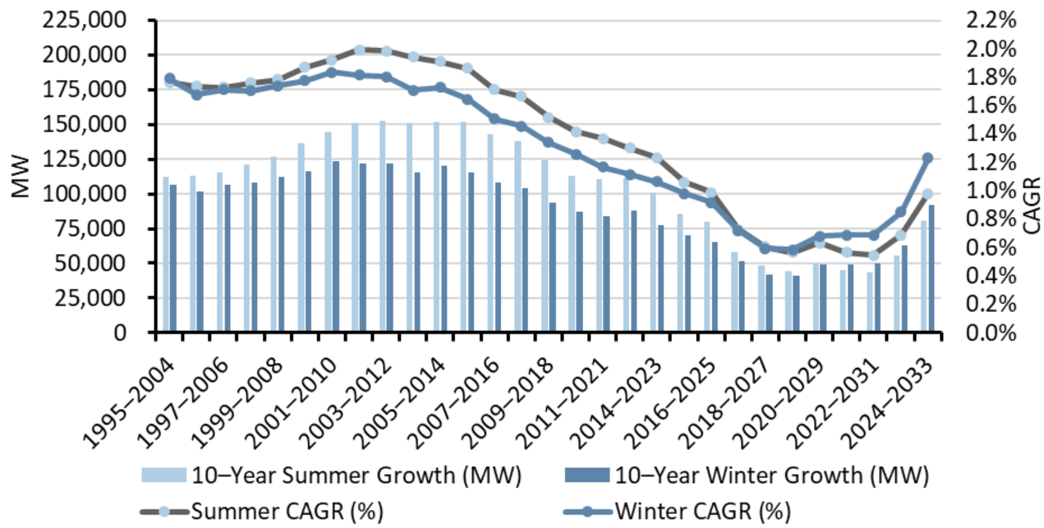
10 Grid Strategies, *2023 Transmission Congestion Report*, September 2024, https://gridstrategiesllc.com/wp-content/uploads/Grid-Strategies_2023-Transmission-Congestion-Report.pdf (hereinafter *2023 Congestion Report*).

11 Millstein, D., et al., *Transmission value in 2023*, Lawrence Berkeley National Laboratory, July 2024, https://emp.lbl.gov/news/transmission-value-2023-market-data-shows-value-transmission-remained-high-certain.

12 *National Transmission Needs Study* at ix.

13 Grid Strategies, "The Era of Flat Power Demand is Over," December 2023, https://gridstrategiesllc.com/wp-content/uploads/2023/12/National-Load-Growth-Report-2023.pdf (hereinafter The Era of Flat Power Demand is Over).

FIGURE 4 NERC historic load growth and future load forecasts[14]



C. The increased role of DOE in planning, permitting, and paying for transmission lines

One key development that was not as present in the initial report card is the role the federal government, specifically DOE, has taken in promoting high-capacity transmission development by addressing the three "Ps" of transmission development: planning, permitting, and paying. The DOE has taken action to support the planning, siting, permitting, and funding of new high-capacity lines, through new programs that were facilitated by the passage of the Infrastructure, Investment, and Jobs Act (IIJA) and Inflation Reduction Act (IRA) in Congress. Most of DOE's actions are undertaken through its new Grid Deployment Office, and that office's role has been formalized in statute.

Traditionally, the role of the DOE has been focused on research and development, including work done by the national laboratories. DOE has continued that work, but now also has a broader emphasis on informing and contributing to transmission planning. For example, the aforementioned *National Transmission Needs Study* is a prerequisite for being designated a National Interest Electric Transmission Corridor (NIETC), which allows transmission projects to obtain additional siting and funding authorities. The DOE also released *An Action Plan for Offshore Wind Transmission Development in the U.S. Atlan-*

14 North American Electric Reliability Corporation, *2023 Long-Term Reliability Assessment*, December 2023, at 33, https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_LTRA_2023.pdf.

tic Region,[15] the *National Transmission Planning Study*,[16] and is working on a study transmission planning study for West Coast Offshore Wind.[17] Alongside the studies, DOE has taken a role in convening parties interested in better transmission planning. The agency has been working with the Atlantic States for over a year to develop a Memorandum of Understanding (MOU) for better interregional transmission planning,[18] and the DOE has also begun a convening process with interested parties on the West Coast.[19]

DOE is also working to address siting and permitting issues through NIETC designations, the Coordinated Interagency Authorizations and Permits (CITAP) Program, and by issuing new categorical exclusions from the National Environmental Policy Act (NEPA). DOE has preliminarily designated ten NIETCs, based, in part, on a determination of need supported by the *National Transmission Needs Study*. If the corridors are finalized, projects that are located within the NIETC corridors will be eligible for additional siting authority from FERC and $2 billion in funding through the Transmission Facility Financing program.[20] The CITAP program aims to help accelerate transmission development by streamlining the federal permitting process for transmission projects with the goal of reducing federal permitting from an average of four years to two years.[21] Lastly, in 2024 DOE added new Categorical Exclusions to the NEPA review process for transmission projects that involve reconductoring or rebuilding a line.[22]

Since the release of the report card, DOE has begun awarding funding to support the development of new high-capacity transmission lines. In 2023 and 2024 DOE awarded $2.5 billion in Transmission Facilitation Program (TFP) funds across seven high-voltage transmission lines that will add almost 10 GW of additional capacity to the grid.[23]

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15 U.S. Department of Energy and Bureau of Ocean Energy Management, *An Action Plan for Offshore Wind Transmission Development in the U.S. Atlantic Region*, April 2024, https://www.energy.gov/gdo/atlantic-offshore-wind-transmission-action-plan.

16 *See National Transmission Planning Study*.

17 *See* GDO, "West Coast Offshore Wind Transmission Planning," accessed October 16 2024, https://www.energy.gov/gdo/west-coast-offshore-wind-transmission-planning (hereinafter West Coast Offshore Wind Transmission Planning).

18 *See* Memorandum of Understanding, "Northeast States Collaborative on Interregional Transmission," July 2024, https://energyinstitute.jhu.edu/wp-content/uploads/2024/07/MOU-Northeast-States-Collaborative-on-Interregional-Transmission.pdf (hereinafter MOU Collaborative on Interregional Transmission).

19 *See* West Coast Offshore Wind Transmission Planning.

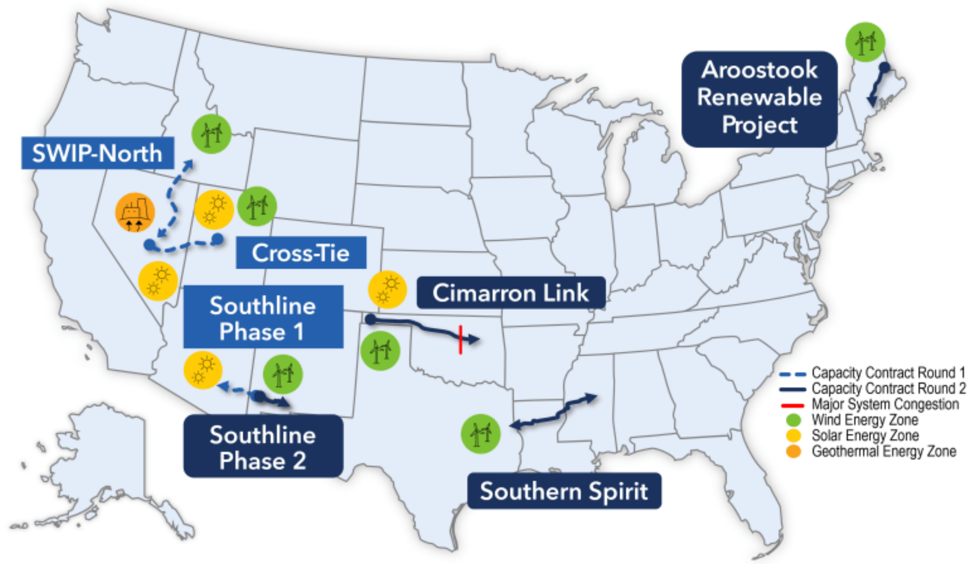
20 *See* GDO, "National Interest Electric Transmission Corridor Designation Process," accessed October 16, 2024, https://www.energy.gov/gdo/national-interest-electric-transmission-corridor-designation-process (hereinafter NIETC Designation Process).

21 *See* GDO, Final Rule on Coordinated Interagency Transmission Authorization and Permits Program, 89 Fed. Reg. 35312, May 1, 2024, https://www.energy.gov/gdo/coordinated-interagency-transmission-authorizations-and-permits-program.

22 *See* U.S. Department of Energy Office of the General Council, Final Rule on National Environmental Policy Act Implementing Procedures, 89 Fed. Reg. 34074, April 30, 2024, https://www.energy.gov/nepa/articles/notice-final-rulemaking-2024.

23 *See* GDO, "Transmission Facilitation Program," accessed October 16, 2024, https://www.energy.gov/gdo/transmission-facilitation-program (hereinafter Transmission Facilitation Program).

FIGURE 5 Transmission Facilitation Program Project Selections[24]



In addition, as a subprogram of the Grid Resilience and Innovation Partnerships (GRIP) funding awards, the Grid Deployment Office through two rounds of funding has awarded over $3 billion through the Grid Innovation Program specifically to support the development of high-capacity transmission projects and the deployment of Advanced Transmission Technologies (ATTs).[25] DOE also released the first round of Transmission Siting and Economic Development (TSED) grants, awarding $371 million to help accelerate the permitting of high-voltage, interstate transmission projects, and support community infrastructure projects. DOE has already announced it is expecting to provide a second round of funding under TSED in early 2025.[26] While DOE funding will accelerate construction of new high-voltage transmission infrastructure, it is simply not enough given relative to the needs and compared to the $25 billion per year currently being spent on transmission.[27]

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24 *Id.*

25 *See* GDO, "Grid Resilience and Innovation Partnerships (GRIP) Program Projects," accessed October 16, 2024, https://www.energy.gov/gdo/grid-resilience-and-innovation-partnerships-grip-program-projects.

26 *See* GDO, "Transmission Siting and Economic Development Grants Program," accessed October 16, 2024, https://www.energy.gov/gdo/TSED.

27 The Brattle Group, *Annual Transmission Investments 1996-2023*, July 2024, at 1, https://www.brattle.com/wp-content/uploads/2023/07/Annual-US-Transmission-Investments-1996%E2%80%932023.pdf.

III. CAISO

SUMMARY

CAISO received one of the highest grades for transmission planning in the initial 2023 report card for its proactive, scenario-based, annual transmission plans, as well as the start of its 20-year transmission outlook. CAISO is the only ISO/RTO that has consistently been performing such planning for over a decade. Since the release of the initial report card, the region has maintained progress in its regional planning processes by adopting an even more ambitious *2023-2024 Transmission Plan* in May 2024, which contains more than $6 billion in transmission investments as well as long-term plans to develop offshore wind. CAISO's *2024 20-Year Transmission Outlook* also identifies several potential HVDC and advanced reconductoring projects to help access offshore and out-of-state wind. CAISO also continues to build on its interregional transmission planning and development strategy to procure resources from outside the state by approving more interregional lines through the Subscriber Participating Transmission Owner (PTO) process. CAISO has indicated that it believes it has many of the components needed for compliance with Order No. 1920 and has stated it will be soliciting feedback and input from interested parties on compliance with Order No. 1920 through the end of 2024 and will begin its State Engagement Period on November 1, 2024.

UPDATE ON CAISO'S TRANSMISSION PLANNING AND DEVELOPMENT

A. CAISO continues to build on previous annual transmission plans

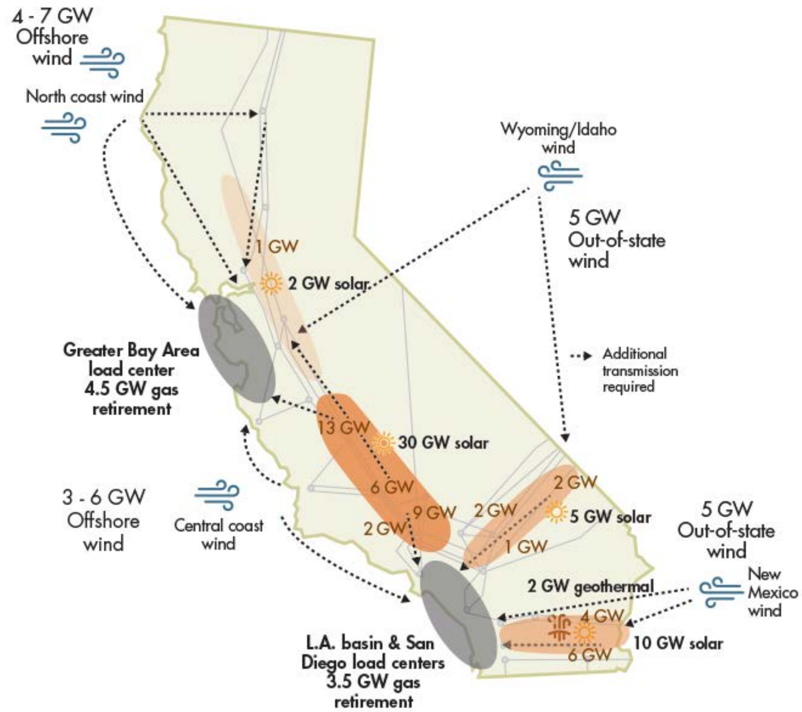
Since ACEG published its report card in 2023, CAISO has continued to build on its proactive, scenario-based transmission planning processes. In May 2024, the CAISO board approved the *2023-2024 Transmission Plan*. The *2023-2024 Transmission Plan* is the result of a close collaboration between CAISO and California state agencies, including the California Public Utilities Commission (CPUC) and the California Energy Commission (CEC), to develop the load forecast, generation scenarios, resource zones, and transmission projects.[28] The 2023-2024 plan recommends 26 projects with an estimated cost of $6 billion.[29] The plan builds on the previously established zonal approach, where specific resource zones and related transmission upgrades are identified. This coordinated process between CAISO, CPUC, and CEC and the resulting identification of resource zones helps better synchronize transmission planning, the interconnection process, and the CPUC's Integrated Resource Planning process and resource procurement by Load Serving Entities.[30]

28 The nature and responsibilities of these entities was established through a 2022 Memorandum of Understanding. *See* "Memorandum of Understanding Between The California Public Utilities Commission (CPUC) And The California Energy Commission (CEC) And The California Independent System Operator (ISO) Regarding Transmission and Resource Planning and Implementation," December 2022, https://www.caiso.com/Documents/ISO-CEC-and-CPUC-Memorandum-of-Understanding-Dec-2022.pdf.

29 CAISO, 2023-2024 Transmission Plan, May 23, 2024, at 5, https://www.caiso.com/documents/iso-board-approved-2023-2024-transmission-plan.pdf (hereinafter *CAISO 2023-2024 Transmission Plan*).

30 *Id.* at 1.

FIGURE 6 Map of CAISO's Transmission Development[31]



The transmission plan, approved in May 2024, now estimates that CAISO needs to add 85 GW of new generation capacity by 2035–a significant increase over the 40 GW CAISO projected in the *2022-2023 Transmission Plan*. The growth is driven by significant increases in load electrification from fuel switching and electric vehicle deployment.[32] The load growth in the *2023-2024 Transmission Plan* requires CAISO to add roughly 8 GW of new generating resources annually, including a total of more than 14 GW of out-of-state wind, solar, and geothermal resources and 4.7 GW of offshore wind generation. To accomplish this, the transmission plan recommends 26 transmission projects with an estimated cost of $6.1 billion. The proposed projects include a new 500 kV substation of North Coast offshore wind and two new 500 kV transmission lines to facilitate the development of offshore wind generation, which was the focus of the sensitivity study in the *2023-2024 Transmission Plan*. As discussed in the previous report card, because CAISO's reliability, policy, and economic planning happen sequentially and transmission optimi-

31 CAISO, "Taking the Long View: The ISO's Collaborative Approach to Transmission Planning & Coordination," April 25, 2024, https://www.caiso.com/about/news/taking-the-long-view-the-isos-collaborative-approach-to-transmission-planning-coordination (hereinafter "CAISO Taking the Long View").

32 *CAISO 2023-2024 Transmission Plan* at 14-15.

zation largely happens in coordination with the resource buildout in the CPUC's capacity expansion modeling, no economic projects were selected again with this plan. CAISO did identify opportunities for economic projects to relieve congestion but none of the projects were recommended in the ISO's final plan.[33]

B. Limited review of Advanced Transmission Technologies

The *2023-2024 Transmission Plan* also initiated a limited review of ATTs, including High Performance Conductors and Grid Enhancing Technologies, which include DLRs, APFCs, and Topology Optimization, with CAISO noting it only evaluates the technologies on a case-by-case or for specific applications.[34] The consideration of ATTs is a good step forward, but a more holistic incorporation of the technologies into planning is likely required by FERC Order No. 1920 and by the state of California itself, which passed a law in 2024 to require the study of cost-effective ATT deployments by Transmission Owners (TOs) and the inclusion of beneficial projects in the transmission planning process.[35]

C. Updated 20-year transmission outlook

In July 2024, CAISO also issued its 2024 *20-Year Transmission Outlook* ("2024 Outlook"). The 2024 Outlook incorporates transmission projects approved since 2022 and assesses how changes in load and resource forecasts since 2022 would affect transmission investments needed by 2045. The *2022 20-Year Transmission Outlook* projected that CAISO would need an additional 120 GW of new resources requiring a $30 billion investment in transmission. The 2024 Outlook, which has updated load forecasts and includes more offshore wind resources, now estimates an investment of $45.8 billion to $63.2 billion is required to interconnect 165 GW of new resources. The cost increase is largely due to load growth and added offshore wind infrastructure. The outlook identified a significant need for investment in new HVDC projects and also identified two potential candidates for reconductoring with High Performance Conductors.[36] While releasing the 2024 Outlook, CAISO stated that it believes its current transmission planning processes have most of the components needed for compliance with Order No. 1920, and that it will be soliciting feedback from interested parties on compliance with Order No. 1920 through the end of

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33 *Id.* at 2-4.

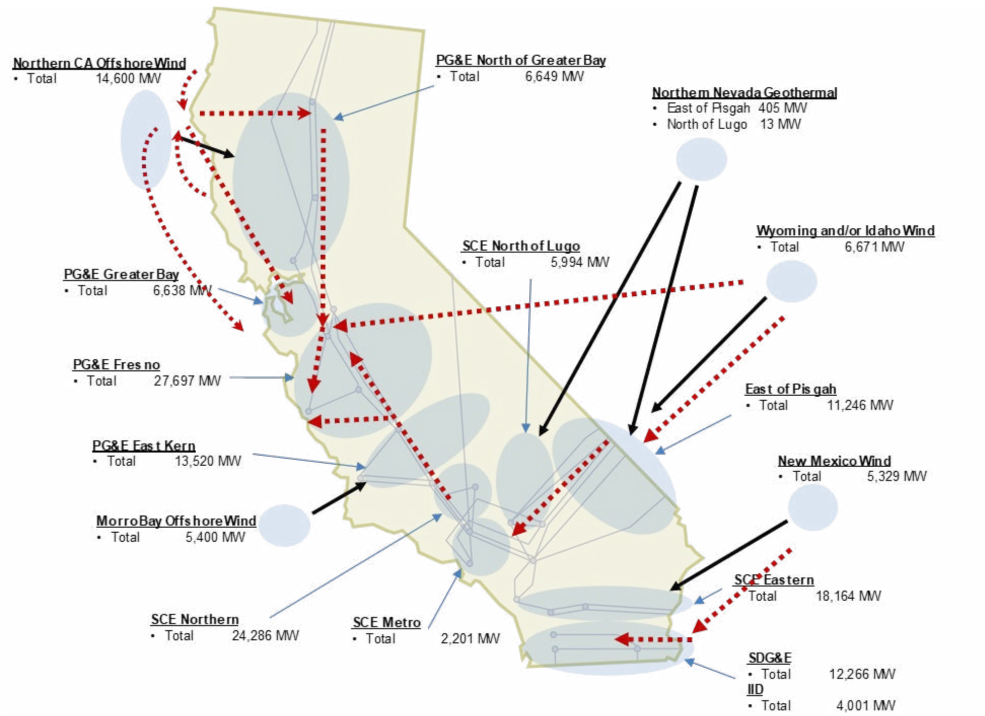
34 *Id.* at 24-27.

35 Senator Padilla, California State Senate, S.B. 1006, February 2024, https://leginfo.legislature.ca.gov/faces/billStatusClient.xhtml?bill_id=202320240SB1006.

36 CAISO, *2024 20-Year Transmission Outlook*, July 31, 2024, https://www.caiso.com/documents/2024-20-year-transmission-outlook-jul-31-2024.pdf (hereinafter *CAISO 20-Year Outlook*).

2024.[37] In October 2024, CAISO also announced it will be initiating the six-month State Engagement Period with Relevant State Entities on November 1, 2024 for the development of Long-Term Cost Allocation and/or a State Agreement Process as required under Order No. 1920.[38]

FIGURE 7 2024 20-year Transmission Investment Outlook[39]



D. CAISO continues its previous interregional transmission development

In the 2023 report card, we noted that CAISO had initiated the Subscriber PTO model to help integrate out-of-state resources that California load-serving entities had procured and approved one project under the model, TransWest Express. The Subscriber PTO model allows CAISO to develop transmission lines outside of its footprint and creates a cost recovery mechanism for developers. CAISO filed the model with FERC in September

37 Millar, N., "The ISO posts an updated 20-Year Transmission Outlook," July 31, 2024, https://www.caiso.com/about/news/the-iso-posts-an-updated-20-year-transmission-outlook#:~:text=In%20addition%2C%20the%20ISO%20is,to%20a%20carbon%2Dfree%20grid.

38 CAISO, "FERC Order No. 1920 Engagement Period to start 11/1/24," October 16, 2024, https://www.caiso.com/notices/ferc-order-no-1920-engagement-period-to-start-11-1-24.

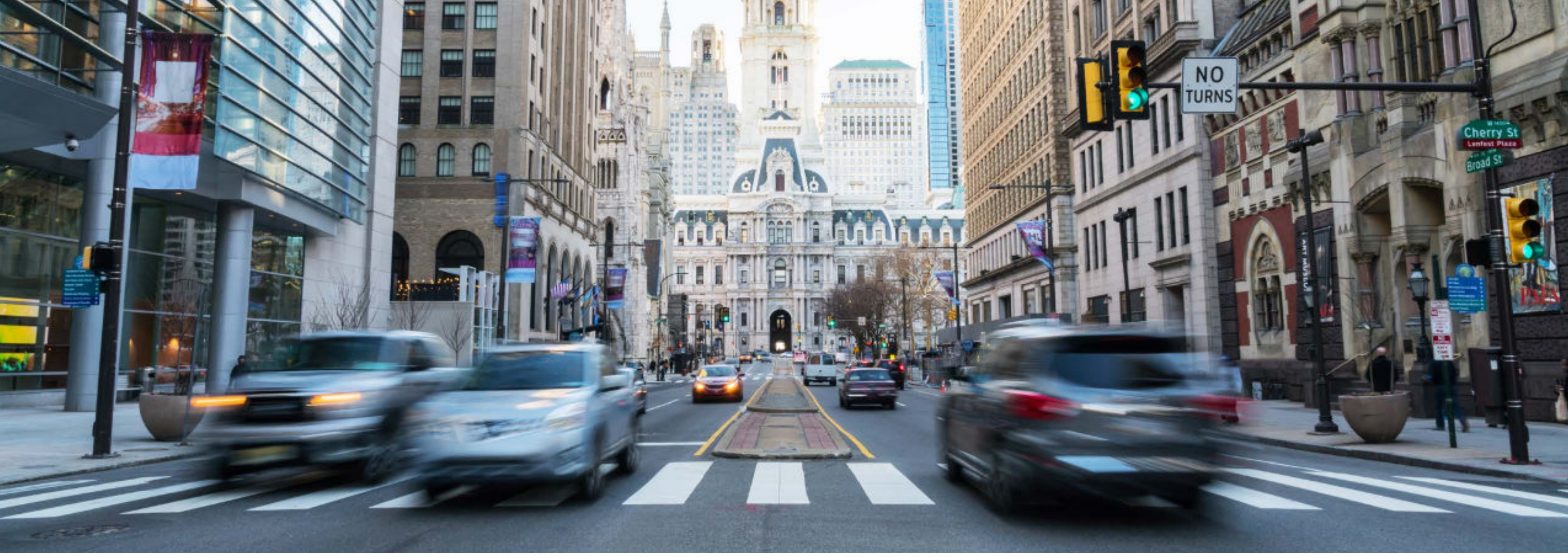
39 *CAISO 20-Year Outlook* at 4.

2023 and FERC approved the Subscriber PTO model in March 2024.[40] CAISO continues to utilize the model, approving two new transmission lines under it: the SunZia transmission project and the Southwest Intertie Project (SWIP) North.[41] CAISO has also been an active participant in the Western Transmission Expansion Coalition (WestTEC) efforts, discussed further below, and continues to participate in the Order No. 1000 interregional planning processes with NorthernGrid and WestConnect, but there have still been no projects identified through the interregional process.[42]

40 *See* Order Accepting Proposed Tariff Revisions re California Independent System Operator Corporation under ER23-2917, FERC Docket No. ER23-2917-001, March 12, 2024, https://elibrary.ferc.gov/eLibrary/filelist?accession_number=20240312-3078&optimized=false.

41 *CAISO 2023-2024 Transmission Plan* at 101-102.

42 *Id.* at 121-127.



IV. PJM

SUMMARY

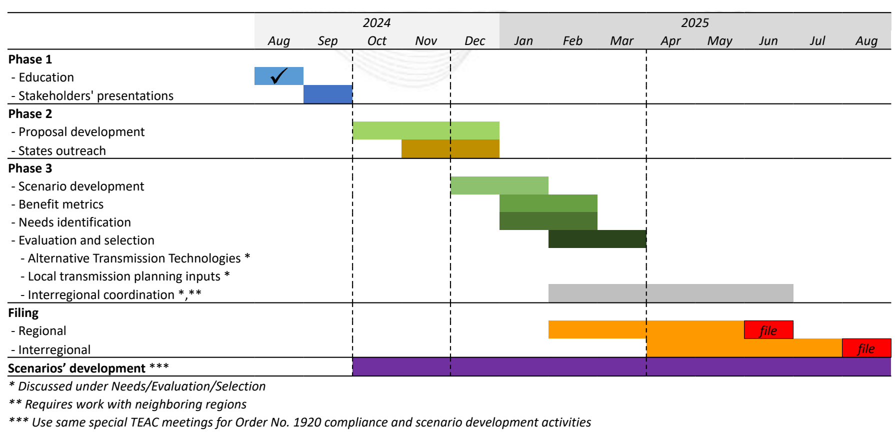
PJM received one of the lowest grades in the previous report card among the regions with an organized market, largely because of its siloed and reactive transmission planning processes. In the interim, PJM began taking steps to improve its transmission planning processes. In July 2023, PJM started discussions to initiate a Long-Term Regional Transmission Planning (LTRTP) process through which PJM proposed to develop a proactive, scenario-based, long-term regional transmission planning process. After the proposed LTRTP reforms failed to receive stakeholder approval, PJM merged its process for revising long-term planning into its compliance efforts for FERC Order No. 1920. PJM has received presentations and comments from interested parties on how it should comply with Order No. 1920 and plans to begin scenario development in December 2024. PJM has also taken small steps forward on interregional planning, initiating a small, joint study with MISO. In addition, several states in PJM have been working with New England states and New York on better interregional transmission planning, largely to support the development of offshore wind generation. PJM has multiple efforts underway, but it is not yet clear what the outcome will be and how effective any planning changes will be for the region. New investments in high-capacity transmission are needed as the region is facing some of the largest load growth in the country along with significant generation retirements.

UPDATE ON THE PJM'S TRANSMISSION PLANNING AND DEVELOPMENT

A. PJM merges its long-term transmission planning reforms with Order No. 1920 compliance

In July 2023, PJM began a series of workshops proposing reforms to its LTRTP process that aligned the region more closely with what was proposed in FERC's Long-Term Transmission Planning NOPR,[43] and also sought input from interested parties.[44] PJM's proposed reforms to its LTRTP process incorporated the development of three scenarios that would include variations in forecasts of load growth, generation, and retirement and different combinations of federal, state, and local policies.[45] PJM also proposed to evaluate four broad categories of benefits including: reduced loss of load, avoided generation investments, expanded production cost savings, and avoided cost of transmission replacements.[46] The proposed changes to PJM's transmission planning were never adopted because interested parties voted to wait for FERC to finalize its long-term transmission planning rule.[47] After the stakeholder vote, PJM decided to merge its LTRTP reforms with its Order No. 1920 compliance process.

FIGURE 8 PJM's Order 1920 compliance timeline[48]



43 Now Order No. 1920.

44 *See* PJM, "Long-Term Regional Transmission Planning Workshop," accessed October 16, 2024, https://www.pjm.com/committees-and-groups/workshops/ltrtp.

45 PJM, "Request for Rehearing and Clarification of PJM Interconnection, LLC in Docket No. RM21-17," June 12, 2024, at 17-18; https://www.pjm.com/-/media/documents/ferc/filings/2024/20240612-rm21-17-000.ashx.

46 *Id.* at 28.

47 PJM, "FERC Order No. 1920 Update," June 27, 2024, https://www.pjm.com/-/media/committees-groups/committees/mrc/2024/20240627/20240627-item-07---ferc-order-no-1920-update---presentation.ashx.

48 PJM, "FERC Order No. 1920 Activities Plan," August 27, 2024, at 2, https://www.pjm.com/-/media/committees-groups/committees/teac/2024/20240827-special/item-04---ferc-order-1920-timeline---presentation.ashx.

With the issuance of FERC Order No. 1920 and PJM's proposed reforms to its LTRTP and its interconnection reforms New Jersey decided to put on hold the State Agreement Approach (SAA) 2.0, which was intended to develop more transmission capacity to interconnect offshore wind.[49]

B. PJM Regional Transmission Expansion Plan (RTEP) and Supplemental Projects

While PJM works to reform its long-term transmission planning, the region has had significant transmission investments arise through the PJM RTEP process and the development of Supplemental Projects,[50] particularly due to load growth. The 2023 RTEP plan included roughly $9 billion in transmission investments including the RTEP Baseline projects, network upgrades, and the Supplemental Projects that were approved by the PJM board.[51] Supplemental Projects make up roughly a quarter of the identified transmission investments or $2.4 billion. Still, as the figure below shows, for the last decade, Supplemental Projects have consistently represented a larger share of PJM's transmission investment.

FIGURE 9 PJM historical transmission investments.[52]

The *2024 Long-Term Load Forecast Report* expects even higher load growth than the 2023 forecast and estimates total annual energy use to increase nearly 40% by 2039 and

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49 New Jersey Board of Public Utilities, "New Jersey SAA 2.0 Update," June 4, 2024, https://www.pjm.com/-/media/committees-groups/committees/teac/2024/20240604/20240604-item-01---njbpu-presentation.ashx.

50 Supplemental Projects refer to transmission expansion or enhancements not needed to comply with PJM reliability, economic, or public policy (SAA) transmission planning. Transmission Owners propose Supplemental Projects, which encompass local upgrades that expand or enhance the transmission system to maintain reliability, enhance resilience, improve service to customers, or address transmission facilities at the end of their useful life. Supplemental Projects do not require PJM board approval, and there may be limited FERC or state review of these projects. *See* David Gardiner and Associates, *Consumer Advocates of the PJM States (CAPS) PJM Transmission Handbook Volume IV: Transmission Planning in PJM*, February 2024, https://www.dgardiner.com/wp-content/uploads/2024/03/CAPS-Transmission-Handbook-Volume-4.pdf ("hereinafter *PJM Transmission Handbook Volume IV: Transmission Planning in PJM*).

51 PJM, *RTEP 2023*, March 7, 2024, at 4, 62, https://pjm.com/-/media/library/reports-notices/2023-rtep/2023-rtep-report.ashx.

52 *Id.* at 298.

summer peak load to grow 42 GW, which is an almost 30% increase from 2024. The rapid rise in load growth is largely due to the significant development of large loads, in particular, new data centers and manufacturing facilities.[53] Given the investment in the 2023 RTEP, it is expected the 2024 investment may be even larger to help meet continued load growth. For example, American Electric Power, Dominion Energy Virginia, and FirstEnergy have already announced that for the 2024 RTEP, they proposed multi-state 765-kV transmission projects, including a $1.9 billion project, using an "innovative joint planning agreement."[54]

C. Slow interregional progress related to offshore wind development, joint MISO study

PJM has also taken small steps forward on interregional planning. In July 2024, DOE announced that ten states, including Delaware, Maryland, and New Jersey from the PJM footprint, have signed a MOU which "establishes a non-binding framework to coordinate enhanced interregional transmission planning and development."[55] A key component of this MOU is better coordination on the planning and development of transmission to support offshore wind generation with the states agreeing to develop a strategic action plan.[56] In addition, PJM and MISO initiated a new joint interregional transfer study. The goal of the study is to identify projects near the PJM-MISO seam that can incrementally enhance interregional transfer capabilities.[57] MISO and PJM have both indicated the study itself will have a limited scope and only small projects with near-term construction timelines are expected to be identified. The most likely outcome is the study will aid future work for both regions and help align joint modeling.[58] State regulators have expressed concerns that the narrow scope of the study falls short of their request for a more robust interregional transmission planning process.[59]

53 PJM, "PJM Publishes 2024 Long-Term Load Forecast," January 8, 2024, at 6 https://insidelines.pjm.com/pjm-publishes-2024-long-term-load-forecast/.

54 Howland, E., "AEP, Dominion, FirstEnergy propose joint 765-kV transmission projects across PJM," Utility Dive, October 8, 2024, https://www.utilitydive.com/news/aep-dominion-firstenergy-pjm-transmission-projects-rtep/729168/.

55 *See* MOU Collaborative on Interregional Transmission at 1.

56 Walton, R., "10 Northeastern states agree to collaborate on interregional transmission development," Utility Dive, July 10, 2024, https://www.utilitydive.com/news/10-northeast-new-england-states-collaborate-interregional-transmission-offshore-wind/720936/ ("Utility Dive Northeastern States MOU")

57 PJM, "Two Major Grid Operators Embark on Joint Planning Endeavor To Enhance Reliability," May 9, 2024, https://insidelines.pjm.com/two-major-grid-operators-embark-on-joint-planning-endeavor-to-enhance-reliability/.

58 Durish Cook, A., "Smaller Projects Expected from Maiden MISO-PJM Joint Tx Study," RTO Insider, May 30, 2024, https://www.rtoinsider.com/80277-smaller-projects-expected-maiden-miso-pjm-joint-tx-study/ (hereinafter RTO Insider Smaller Projects Expected).

59 Durish Cook, A., "Some MISO Regulators Signal Early Discontent with New MISO-PJM Interregional Study," RTO Insider, August 18, 2024, https://www.rtoinsider.com/85585-miso-regs-signal-early-discontent-new-interregional-study/ (hereinafter Regulators Signal Discontent with MISO-PJM Interregional Study).

V. MISO

SUMMARY

In 2023, MISO received one of the highest grades in the report card for its proactive, multi-value, scenario-based Long Range Transmission Planning (LRTP) initiative. The region has largely stayed the course, moving forward with LRTP Tranche 2.1, a $21.8 billion transmission investment in 3,600 miles of high-capacity transmission. However, the concerns raised in the original report card about MISO South's lack of proactive transmission planning remain. In addition, the original future scenarios used for the LRTP process do not fully capture new large loads emerging across the country. MISO's existing LRTP processes are largely aligned with the requirements in Order No. 1920, but the region has stated it plans to ask for a one-year extension on compliance.

UPDATE ON MISO'S TRANSMISSION PLANNING AND DEVELOPMENT

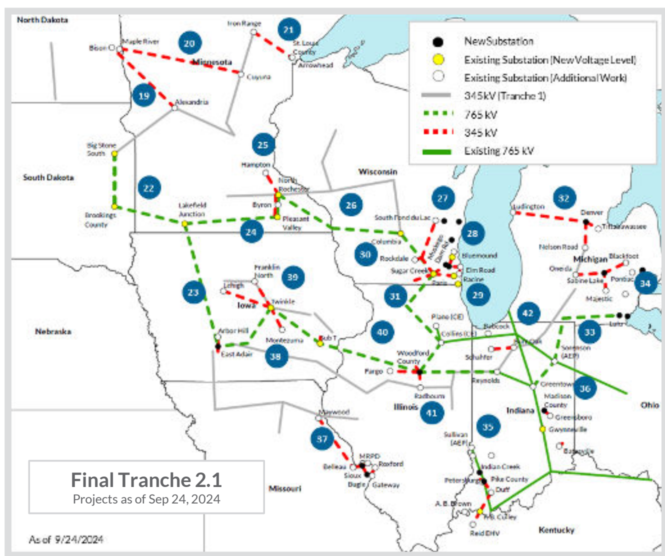
A. MISO moves forward with LTRP, planning for Tranche 2.1 and development of Tranche 1

Since the last report card in 2023, MISO has moved forward with its LRTP process, developing the second tranche for the MISO North region. For its second tranche, MISO has proposed a $21.8 billion portfolio of 1,800 miles of 765 kV backbone transmission lines and 1,800 miles of 345 kV lines to support the development of the backbone transmission lines.

MISO has indicated that approximately 70 percent of the lines in the recommended LRTP Tranche 2.1 portfolio are proposed on new transmission corridors, which is different from Tranche 1, where roughly 80 percent of the line miles were proposed on existing corridors.[60]

MISO's recommended Tranche 2.1 has two promising developments and improvements over the previous portfolio. First, MISO used nine benefits for the benefit-cost analysis for the recommended Tranche 2.1 portfolio, instead of the previous six benefits used to evaluate its Tranche 1 portfolio.[61] The nine benefits are essentially the same as the seven benefits required to be evaluated in FERC Order No. 1920 plus a quantification of the benefits of decarbonization.[62] Using these nine benefits, MISO determined that the recommended Tranche 2.1 portfolio under Future 2A provides a regional benefit of at least $1.80 for every $1 invested.[63] Second, in its recommended Tranche 2.1 portfolio, MISO has included four 765 kV tie-lines that would connect with substations in PJM.[64] These proposed lines would add significant additional interregional transfer capability between MISO and PJM.

FIGURE 10 **LRTP Recommended Tranche 2.1 Portfolio**[65]



60 *See* MISO, "LRTP Tranche 2.1 Portfolio Update," September 24, 2024, https://cdn.misoenergy.org/20240924%20LRTP%20Workshop%20Item%2002%20Tranche%202.1%20Final%20Portfolio%20Overview649676.pdf (hereinafter LRTP Tranche 2.1 Portfolio Update); *See also* MISO, "LRTP Tranche 2.1 Draft Addendum Appendix A," September 24, 2024, https://cdn.misoenergy.org/20240924%20LRTP%20TR2.1%20Draft%20Appendix%20A649775.xlsx.

61 *See* MISO, *LRTP Tranche 2 Business Case Metrics Methodology Whitepaper,* October 1, 2024, https://cdn.misoenergy.org/LRTP%20Tranche%202%20Business%20Case%20Metrics%20Methodology%20Whitepaper633738.pdf.

62 Order No. 1920 at P 720.

63 MISO, "LRTP Tranche 2.1 Benefits Analysis Results Review," September 25, 2024, at 2-3, https://cdn.misoenergy.org/20240925%20LRTP%20Workshop%20Item%2001%20Tranche%202.1%20Business%20Case%20Overview649810.pdf.

64 LRTP Tranche 2.1 Portfolio Update at 1.

65 *Id.*

While MISO had one of the best transmission planning grades in the initial report card, second only to CAISO, there are a few places where MISO has room for improvement, including updating scenarios and the inclusion and modeling of various transmission technologies. For the LRTP Tranche 2.1 modeling, MISO conducted a scenario refresh for its three future scenarios used in the LTRP process. However, the inputs refresh is based on underlying modeling and assumptions from 2019 and 2020, and does not adequately capture the significant load growth the region is facing.[66] MISO attempted to address this fact using the slightly larger load growth in Future 2A for its model. MISO's Future 2A estimates load growth of approximately 30% over 20 years, largely due to electrification, not large loads, raising concerns that actual load growth will be even higher.[67] In addition, MISO did not include any ATTs as a part of its LRTP Tranche 2.1 planning, and MISO considered HVDC on a limited basis despite the long distances that exist in the Midwest (HVDC is relatively more economical the longer the distance). For compliance with Order No. 1920, MISO announced in October 2024 it will file a request for a one-year extension of the deadline for compliance with Order No. 1920.[68]

B. Limited progress on interregional transmission planning as Joint Targeted Interconnection Queue (JTIQ) moves forward, joint PJM study initiated

Since the release of the first report card, MISO has made incremental steps forward on interregional transmission planning. MISO and SPP continue to move forward with their JTIQ portfolio. The regions have agreed to a Joint Operating Agreement and cost allocation methodology, which have been filed at FERC.[69] However, not all parties in MISO and SPP were supportive of the cost allocation structure which proposes to allocate costs solely to developers.[70] The JTIQ portfolio was also awarded $464 million in the first round of DOE GRIP funding announced in October 2023.[71] Both regions have indicated there will likely be a second round of planning. As discussed in the original report, this is a good step forward in aligning processes to work on joint planning and will facilitate the connection of 28-53 GW of new generation, but the process falls short of true, optimized interregional planning which would consider a more holistic set of transmission

66 MISO, *MISO Futures Report Series 1A*, November 1, 2023, at 2-10, 27-46, https://cdn.misoenergy.org/Series1A_Futures_Report630735.pdf.

67 *Id.*; *See also* MISO, "Long Range Transmission Planning (LRTP) Workshop," March 15, 2024, https://www.misoenergy.org/events/2023/long-range-transmission-planning-lrtp---march-15-2024/.

68 MISO, "Planning Advisory Committee Liaison Report," October 16, 2024, at 8, https://cdn.misoenergy.org/20241016%20PAC%20Item%2003%20Liaison%20Report652683.pdf.

69 *See generally* tariff revisions and JOA filings from SPP and MISO in FERC Docket Nos. ER24-2797-000, ER24-2798-000, ER24-2871-000, ER24-2825-000. https://elibrary.ferc.gov/eLibrary/filelist?accession_number=20240826-5149&optimized=false

70 *See* Protest of the Clean Energy Associations to the 08/16/2024 filings of Southwest Power Pool Inc. et al. under ER24-2797, et al., https://elibrary.ferc.gov/eLibrary/filelist?accession_number=20240919-5161&optimized=false (hereinafter Protest of Clean Energy Associations).

71 GDO, "Joint Targeted Interconnection Queue Transmission Study Process and Portfolio," October 18, 2023," https://www.energy.gov/sites/default/files/2023-11/DOE_GRIP_3048_MN%20Dept%20of%20Commerce_v4_RELEASE_508.pdf (hereinafter GDO JTIQ Award).

benefits beyond simply easing the interconnection process. However, cost allocation for interregional transmission will require improvements to comply with beneficiary-pays principles. In addition, MISO and SPP have announced that they are engaging in a new planning approach at their seam in 2025. The study is intended to identify near-term upgrades that incrementally enhance transfer capability, similar to the PJM study, but may also allow for the identification of transmission projects with multiple benefits.[72]

MISO and PJM have initiated a new joint interregional transfer study.[73] The goal of the study is to identify projects near the MISO-PJM seam that can incrementally enhance interregional transfer capabilities.[74] MISO and PJM have both indicated the study itself will have a limited scope and only small projects with near-term construction timelines are expected to be identified. The most likely outcome is the study will aid future work for both regions and help align joint modeling.[75] State regulators have expressed concerns that the narrow scope of the study falls short of their request for a more robust interregional transmission planning process.[76]

C. MISO South still has no proactive, scenario-based, multi-value planning

As was discussed in the initial report card, MISO's proactive planning practices do not extend to the southern part of the region. This lack of proactive planning in MISO South has increasingly become a problem as the utilities have advanced significant investments in new transmission capacity through the local transmission planning process, and MISO's reliability and expedited project review processes. In 2023 MISO's annual Transmission Expansion Plan (MTEP) set a record with over $9 billion in upgrades, and while the 2024 MTEP is not quite as high as 2023, MISO is still estimating the 2024 MTEP will result in a $6.7 billion investment. The largest bucket of projects remains projects to address load growth and local reliability criteria, with MISO South accounting for six of the ten most expensive projects.[77] The current plan is for MISO to begin Tranche 3, which is supposed to apply the proactive, multi-value, scenario-based planning to its Southern region after the conclusion of Tranche 2.1. There is not currently an agreed-upon cost allocation methodology for Tranche 3, although utilities and state regulators continue to hold discussions on this issue.

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72 *See* MISO and SPP, "SPP-MISO 2024 Coordinated System Plan (CSP) Kick-Off and Discussion," September 9, 2024, https://cdn.misoenergy.org/20240909%20MISO-SPP%20IPSAC%20Meeting646409.pdf ("SPP-MISO CSP").

73 MISO, "Two Major Grid Operators Embark on Joint Planning Endeavor To Enhance Reliability," May 9, 2024, https://www.misoenergy.org/meet-miso/media-center/2024/two-major-grid-operators-embark-on-joint-planning-endeavor-to-enhance-reliability/.

74 MISO and PJM, "PJM and MISO Interregional Transfer Capability Study (ITCS) FAQ," accessed October 16, 2024, https://cdn.misoenergy.org/0241122%20MISO%20PJM%20-%20ITCS%20FAQ650732.pdf.

75 *Id.*; *See also* RTO Insider Smaller Projects Expected.

76 Regulators Signal Discontent with MISO-PJM Interregional Study

77 Durish Cook, A., "MTEP 24 Reaches Almost $7B," September 10, 2024, at 24, https://rtowww.com/wp-content/uploads/newsletters/2024-09-10-RTO-Insider.pdf.

IV. ISO New England

SUMMARY

ISO-NE has been moving forward with its new Long-Term Transmission Planning (LTTP) process. The LTTP process implements a proactive, multi-value long-term planning that was requested by New England states to help achieve state policy goals. ISO-NE filed tariff reforms for its LTTP with FERC in May 2024, which were approved in July 2024. The FERC-approved LTTP tariff revisions are directionally good and promising reforms, but it is not fully clear how the LTTP process will be harmonized with Order No. 1920 requirements. Nonetheless, in October 2024 the New England states signaled their intent to focus the first LTTP solicitation on unlocking new generation in northern Maine and New Hampshire and strengthening transfer capacity along the North-South interface. ISO-NE has initiated the required State Engagement Period for the Relevant State Entities for Order No. 1920 compliance on cost allocation as well as a compliance process for New England Power Pool (NEPOOL) members. On interregional transmission, ISO-NE has made progress with other Atlantic Coast states on coordination of offshore wind transmission, and the region as a whole is facing rising costs from local transmission projects.

UPDATE ON THE ISO-NE'S TRANSMISSION PLANNING AND DEVELOPMENT

A. FERC approves ISO-NE's proactive, multi-value transmission planning process

One significant change in New England over the last year are the revisions ISO-NE made to its transmission planning to implement a proactive, multi-value long-term transmission planning process, known as Long-Term Transmission Planning.[78] The reforms kicked off after the New England States Committee on Electricity (NESCOE) called for ISO-NE to initiate a more proactive transmission planning process that extended beyond a 10-year planning horizon and helped the New England states satisfy their own state laws.[79] In response to this request, ISO-NE embarked on a two-phased update to the tariff language to support long-term transmission planning. Phase One included tariff reforms which allowed NESCOE to initiate Longer-Term Transmission Planning Studies (LTTS). These LTTSs are proactive assessments of the future electricity system and associated transmission needs. Study inputs (or scenarios) are specified by NESCOE, but can include state policies, load growth, and extreme weather. FERC approved Phase One tariff reforms in 2022.[80] NESCOE requested that ISO-NE conduct its first LTTS to evaluate the region's resource mix and determine transmission needs in 2050, which resulted in the development of the *2050 Transmission Study*. The *2050 Transmission Study* is an informational-only study that identified potential transmission facilities and provided high-level cost estimates.[81] The study, released in early 2024, relied on inputs from the All Options Pathway of the *Massachusetts' 2050 Deep Decarbonization Roadmap* report.[82] The *Massachusetts' 2050 Deep Decarbonization Roadmap* report included a long-term load forecast which predicted that winter demand would almost triple and New England would transition to a winter peaking system.[83] The study was released in 2020 and therefore may not capture some of the recent trends in new large load growth; however, the ISO-NE's 2024 forecast primarily identified load growth due to the accelerating electrification of heating systems and transportation.[84] The *2050 Transmission Study* also examined the import of approximately 4800 MW using existing HVDC ties with Hydro Quebec in Canada and evaluated several potential new HVDC lines, including the estimated costs.[85]

78 *See* ISO New England, Inc. (ISO-NE), "ISO New England Inc. submits tariff filing per 35.13(a)(2)(iii): Revisions to the Attachment K Longer-Term Transmission Planning Process to be effective 7/9/2024 under ER24-1978," May 9, 2024, https://elibrary.ferc.gov/eLibrary/filelist?accession_number=20240509-5064&optimized=false.

79 NESCOE, "New England States Vision Statement," October 16, 2020, https://nescoe.com/resource-center/vision-stmt-oct2020/.

80 *See* ISO-NE, 178 FERC ¶ 61,137 (2022) (February 2022 Order); https://www.iso-ne.com/system-planning/transmission-planning/longer-term-transmission-studies.

81 *See* ISO-NE, *2050 Transmission Study*, February 12, 2024, https://www.iso-ne.com/static-assets/documents/100008/2024_02_14_pac_2050_transmission_study_final.pdf (hereinafter *2050 Transmission Study*).

82 *See* Massachusetts Executive Office of Energy and Environmental Affairs and The Cadmus Group, *Massachusetts 2050 Decarbonization Roadmap,* December 2020, https://www.mass.gov/doc/ma-2050-decarbonization-roadmap/download.

83 *Id.*

84 ISO Newswire, "New England's electricity use to increase steadily over next decade, according to 2024 CELT Report," May 1, 2024, https://isonewswire.com/2024/05/01/new-englands-electricity-use-to-increase-steadily-over-next-decade-according-to-2024-celt-report/.

85 *2050 Transmission Study* at 12-13, 29-32, and 46-56.

FIGURE 11 2050 Transmission Study Transmission Upgrades and Additions for the New Haven - Essex Roadmap and the Offshore Grid Roadmap[86]

In 2024, ISO-NE finalized Phase Two of its long-term transmission planning process, called Longer Term Transmission Planning (LTTP). FERC approved the tariff language for LTTP in July 2024.[87] The new process allows ISO-NE and NESCOE to procure cost-effective long-term transmission solutions. The new tariff language establishes an evaluation and benefit quantification process for future transmission solutions and a cost allocation methodology. Specifically, ISO-NE will now evaluate the first four listed Order No. 1920 benefits, including: avoided transmission costs, increased reliability, and production cost savings. If a transmission solution demonstrates that the benefits outweigh the costs, it will be selected to move forward in the planning process. It also lays out a process where a state or groups of states can pay for projects that others in the region may not support, and if the costs of a project slightly exceed the benefits, the state or a subset of states can agree to cover the difference.[88]

The new LTTP process is much more closely aligned with the requirements of Order No. 1920 but additional changes are needed for compliance. For example, the LTTP process

86 *Id.* at 45.

87 *See* FERC, "Order Accepting Tariff Revisions, Subject to Condition, and Directing Compliance," Docket No. ER24-1978-000, July 8, 2024, https://www.iso-ne.com/static-assets/documents/100013/er24-1978-000.pdf.

88 *Id.*

does not have a consistent schedule or planning horizon, does not include evaluation of extreme weather scenarios or benefits, and does not address ATTs. ISO-NE also does not develop scenarios for the LTTP process, instead NESCOE submits scenarios or inputs. Another notable distinction in ISO-NE's process is that states will ultimately select and develop chosen transmission projects, whereas Order No. 1920 delegates the selection responsibility to the Transmission Providers. In addition, the LTTP process can be terminated at many points at the discretion of the states and is ultimately voluntary, whereas Order No. 1920 requires regular planning cycles that cannot be terminated at the request of any stakeholder.[89]

In October 2024, the New England states sent a letter letter from NESCOE to ISO-NE signaling their intent for the focus of the first LTTP solicitation to be on interconnecting new generation in northern Maine and New Hampshire and strengthening transfer capacity along ISO-NE's North-South interface,[90] which was identified as an issue in the *2050 Transmission Study*.[91] In the letter NESCOE also highlighted the fact that recent studies, along with the current interconnection queue, indicate roughly 3,000 megawatts (MW) of additional generation capacity could potentially be developed in northern Maine, which is informing the States' interest in transmission solutions that would facilitate the integration of these resources. Solutions brought forth through this regional process would likely be in addition to, rather than in place of, state-specific procurement efforts to bring forth transmission solutions deeper into northern Maine.[92]

ISO-NE has laid out a timeline and schedule of meetings for NEPOOL members for compliance with Order No. 1920 and developed a gap analysis comparing its LTTP process with Order No. 1920 requirements.[93] The NEPOOL meetings are only open to NEPOOL members, and are not open to the general public. ISO-NE also sent a letter in September 2024 to the Relevant State Entities of New England initiating the six-month State Engagement Period for the development of Long-Term Cost Allocation and/or a State Agreement Process as required under Order No. 1920. In the letter, ISO-NE notes the engagement period ends in March 2025 and encourages the Relevant State Entities to en-

89 *See* ISO-NE, "Comparison of ISO-NE LTTP Tariff Provisions to FERC Order 1920 Requirements," September 25, 2024, https://www.iso-ne.com/static-assets/documents/100015/a05_tc_1920_lttp_comparison_chart.docx; *See also* Lang-Ree, C., "Bridging the Gap: New England's Transmission Planning and Order 1920," September 11, 2024, https://www.nrdc.org/bio/claire-lang-ree/bridging-gap-new-englands-transmission-planning-and-order-1920.

90 NESCOE, "Letter on Potential Transmission Needs for a Longer-term Transmission Planning RFP," October 16, 2024, https://nescoe.com/resource-center/lttp-rfp-letter/ (hereinafter NESCOE Letter on Potential Transmission Needs).

91 *2050 Transmission Study* at 22.

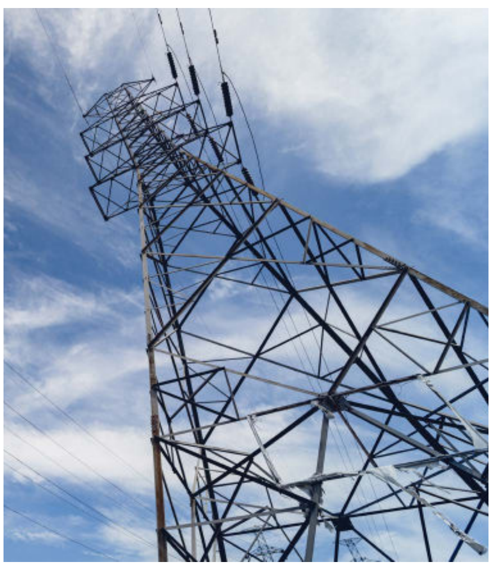
92 NESCOE Letter on Potential Transmission Needs

93 *Id.; See also* ISO-NE, "Order No. 1920 Key Project," accessed October 16, 2024, https://www.iso-ne.com/committees/key-projects/order-no-1920-key-project; See also ISO-NE, "FERC Order No. 1920 Introduction," September 25, 2024, at 11-19, https://www.iso-ne.com/static-assets/documents/100015/a05_tc_order1920_presentation.pdf.

gage through NESCOE, the existing FERC-recognized regional state committee.[94]

B. Slow interregional progress related to offshore wind development

ISO-NE has also made incremental progress on its interregional planning. In July 2024, the DOE announced that ten states, including the six ISO-NE states, signed a MOU which "establishes a non-binding framework to coordinate enhanced interregional transmission planning and development."[95] A key component of this MOU is better coordination on the planning and development of transmission to support offshore wind generation with the states stating they will develop a strategic action plan.[96] The states have been working with DOE on greater coordination of offshore wind transmission development for over a year. In addition, the six ISO-NE states collaborated with New York on the Clean Resilience Link project, a joint application for federal funding through DOE's GRIP program.[97] DOE also identified an interregional corridor as a part of the Preliminary NIETC designations between Massachusetts and New York.[98]



C. ISO-NE continues to face rising costs from local transmission projects

Lastly, ISO-NE is facing significant increases in transmission costs from "asset condition projects." Asset condition projects are generally transmission upgrades identified by TOs to address wear and tear, aging, and end-of-life replacement for existing transmission infrastructure. Asset condition projects are currently projected to account for nearly half of forecasted regional transmission investments in 2024, clocking in at $814 million, and TOs project that value to increase to $965 million in 2025.[99]

94 ISO-NE, "Memo to Relevant State Entities (as identified in FERC Order 1920) Re: Notice of Six-Month Engagement Period on Transmission Cost Allocation," September 9, 2024, https://www.iso-ne.com/static-assets/documents/100015/notice_of_six_month_engagement_period_1.pdf. ("[T]he ISO intends to host two virtual forums to facilitate these discussions. The ISO will provide further details concerning these forums as a follow up to this notice. The forums are likely to be scheduled around November 2024 and February 2025.")

95 *See* MOU Collaborative on Interregional Transmission at 1.

96 *See* Utility Dive Northeastern States MOU.

97 Executive Office of Energy and Environmental Affairs, Massachusetts Department of Energy Resources, Federal Funds & Infrastructure Office, Federal and Regional Energy Affairs, "Press Release: New England States Seek Federal Funding for Significant Investments in Transmission and Energy Storage Infrastructure," April 17, 2024, https://www.mass.gov/news/new-england-states-seek-federal-funding-for-significant-investments-in-transmission-and-energy-storage-infrastructure (hereinafter New England States Seek Federal Funding).

98 *See* NIETC Designation Process.

99 Lamson, J., "NEPOOL Reliability/Transmission Committee Briefs," RTO Insider, August 20, 2024.

FIGURE 12 Transmission Investment in ISO-NE[100]

In response to these rising costs, the NESCOE has begun to raise concerns over the lack of oversight and consideration of project alternatives by TOs in ISO-NE. In February 2023, NESCOE called for reforms to the asset condition process and the development of new guidance.[101] In response, TOs have been working on developing new processes and published the NETOs' Asset Condition Process Guide (Process Guide).[102] However, in a June 2024 memo, NESCOE states that the process guide falls short of the document and reforms being asked for by the New England States.[103]

100 NESCOE, "Memo to New England Transmission Owners Re: Asset Condition Projects and Process Improvements," February 8, 2024, at 3, https://www.iso-ne.com/static-assets/documents/2023/02/2023_02_08_nescoe_asset_conditions_letter.pdf.

101 *See Id.*

102 *See* Burnham, D., "Overview of Joint NETO Asset Condition Process Guide," presentation on behalf of Avangrid Networks, Eversource Energy, National Grid, Rhode Island Energy, Versant Power and VT Transco, May 15, 2024, https://www.iso-ne.com/static-assets/documents/100011/a03_pac_neto_asset_guide_presentation.pdf.

103 NESCOE, "Memo to New England Transmission Owners Re: NETOs' Asset Condition Process Guide in Lieu of a Guidance Document," June 5, 2024, https://nescoe.com/resource-center/feedback-on-asset-condition-process-guide/.

VII. NYISO

SUMMARY

New York continues to make significant investments in transmission, with over $20 billion in investments through various NYISO and state transmission planning processes. Some of that investment has already been completed, such as the AC Public Policy Transmission lines which were discussed in the 2023 report card. Shortly after the report card was published, New York utilities began the Coordinated Grid Planning Process (CGPP), a new long-term, scenario-based transmission planning process aimed at better integrating New York utilities' local transmission planning processes with NYISO's transmission and interconnection planning. New York's utilities have also begun an initiative focused on further study and deployment of ATTs, but the working group has so far had limited results. There is still work to be done to better integrate NYISO's reliability, economic, and public policy planning as well as opportunities to optimize NYISO and the New York Public Service Commission (NYPSC) processes, and it is not yet clear how much of that can be accomplished through the CGPP. In August 2024, NYISO began seeking comments from interested parties on compliance with Order No. 1920 and has said that, in October through December 2024, it will develop a straw proposal for compliance with the rule.

D. New York forges ahead with transmission planning and significant investments

New York continues to move forward with transmission planning and solicitations under its Public Policy Transmission Planning Process (PPTPP). In June 2023, the Propel New York Energy Project was selected to meet the Long Island Offshore Wind Export Public Policy Transmission Need.[104] This $3.3 billion project will connect 3 GW of offshore wind generation by 2030. The project is being jointly developed by New York Power Authority and New York Transco.[105] The latest PPTPP, NYC Offshore Wind Public Policy Transmission Need, started in June 2023 set a goal to deliver at least 4,770 MW of offshore wind generation to New York City with the potential to deliver up to 8 GW of offshore wind. In response to the need, four bids with 28 solutions were received, with the potential for project selection by the end of 2025.[106] Two HVDC lines, Clean Path New York and Champlain Hudson Power Express, are also under construction in NYISO and will deliver a combined 2,500 MW of clean generation from upstate to New York City.

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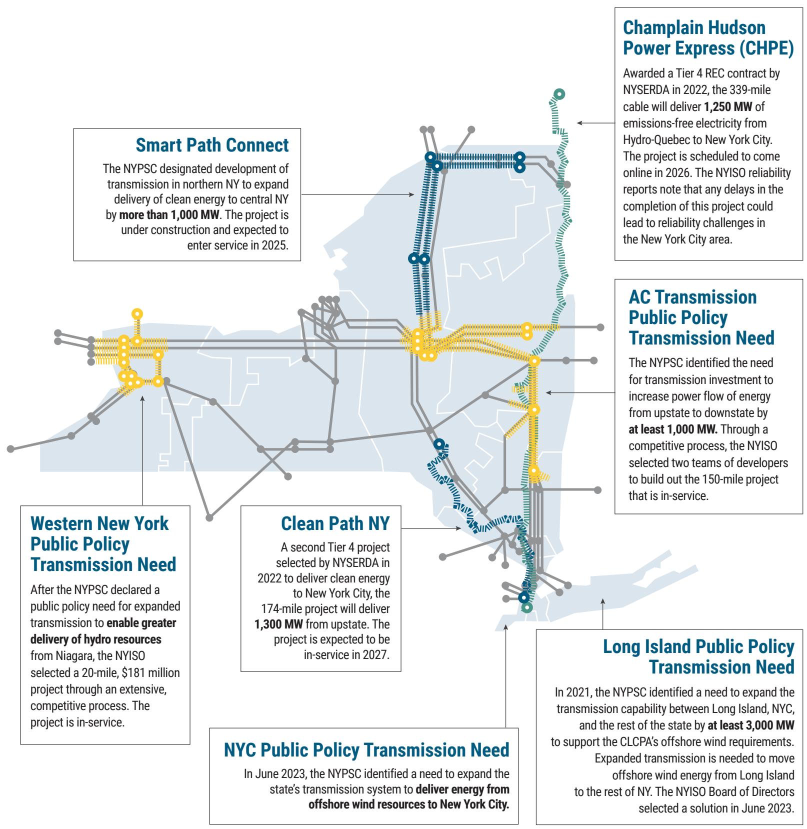
104 NYISO, "PRESS RELEASE | NYISO Board Selects Transmission Project to Deliver Offshore Wind Energy," June 20, 2023, https://www.nyiso.com/-/press-release-%7C-nyiso-board-selects-transmission-project-to-deliver-offshore-wind-energy.

105 Propel NY Energy, accessed October 16, 2024, https://www.propelnyenergy.com/.

106 *See* New York Public Service Commission, "Order Addressing Public Policy Requirements for Transmission Planning Purposes," Case 22-E-0633, https://www.nyiso.com/documents/20142/1406395/PSC-Order-NYC-PPTN.pdf; Gabrielle, V., "NYISO Reveals Bids in NYC Offshore Transmission Solicitation," June 25, 2024, https://www.rtoinsider.com/81885-nyiso-bids-nyc-offshore-transmission-solicitation/#:~:text=NYISO%20this%20month%20received%20four,HVDC%20cables%2C%20or%20interconnection%20points.

FIGURE 13 New and Completed Transmission Projects in New York[107]



NYISO also completed its second biannual *2023-2042 System & Resource Outlook (The Outlook)* as a part of its economic transmission planning. For the Outlook, NYISO expanded the scope of the study to help inform the CGPP process (described further below) by adding two additional scenarios as well as identifying zones/pockets where congestion will likely limit renewables development.[108] The study included significant load growth, projecting that NYISO will become a winter peaking system in the mid-2030s and included projections of large load growth which NYISO projects is the biggest source of load growth in the near term before being overtaken by building and transportation electrification load growth in the 2030s.[109] NYISO still largely views the study as informational; however, the Outlook informs public policy need determinations and the NYPSC has asked utilities to come up with solutions to address concerns identified in prior Outlooks.

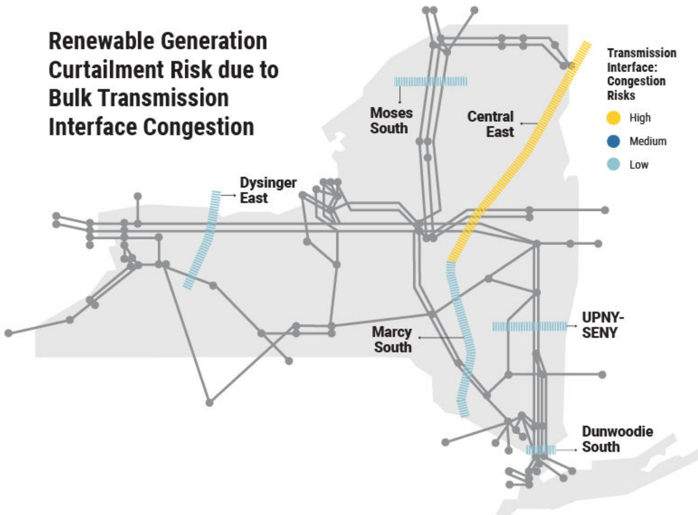
107 NYISO, *2023-2042 System & Resource Outlook (The Outlook)*, July 23, 2024, at 13, https://www.nyiso.com/documents/20142/46037414/2023-2042-System-Resource-Outlook.pdf/8fb9d37a-dfac-a1a8-8b3f-63fbf4ef6167?t=1721752637474 (hereinafter *NYISO Outlook*).

108 *Id.* at 37-71.

109 *Id.* at 30-36.

In response, the utilities have proposed local transmission projects to address the issues. Because the solutions were all local, they likely resulted in missing broader efficiencies.[110]

FIGURE 14 Renewable Generation Curtailment Risk in NYISO[111]



In August 2024, NYISO began seeking comments from interested parties on compliance with Order No. 1920. Over three months from October 2024 to December 2024, NYISO will develop a straw proposal for compliance with the rule and then refine that proposal and develop tariff language from January 2025 through June 2025.[112] In a meeting for interested parties, the NYISO director of system planning stated they were unsure if it was better for the region to "expand the existing process or build an additional tracker on top to comply with the order."[113]

E. New York begins proactive, scenario-based, multi-value local transmission planning process

In addition to the regional planning processes, New York initiated the start of the CGPP in 2023. The goal of the CGPP is to align local utility transmission system planning and devel-

110 NYPSC, "Order Approving Phase 2 Areas of Concern Transmission Upgrades," Case 20-E-0917, February 16, 2023, https://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={0C1FE2AF-2922-4BF5-809C-5C93F4F73121}.

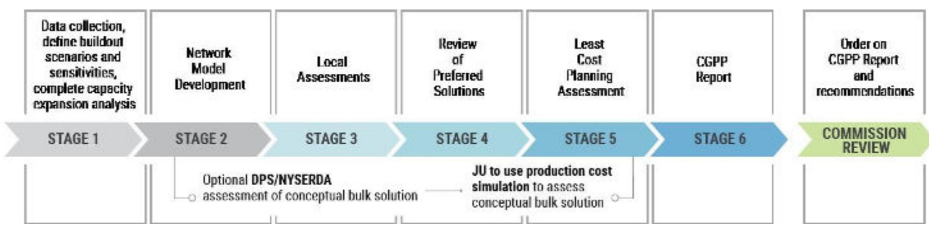
111 *NYISO Outlook* at 15.

112 Lin, Y., "Order No. 1920 Long-Term Regional Transmission Planning," NYISO, August 6, 2024, at 4, https://www.nyiso.com/documents/20142/46217988/13_Order%20No%201920%20ESPWG%20Summary_20240806_final.pdf/46bd915b-ebe5-e054-0833-862dff574e60.

113 Gabrielle, V., "NYISO Previews Work on Compliance with FERC Order 1920," RTO Insider, August 12, 2024, https://www.rtoinsider.com/84896-nyiso-previews-work-on-compliance-with-ferc-order-1920/.

opment with the state's climate law, the Climate Leadership and Community Protection Act (CLCPA), and NYISO's transmission planning and generator interconnection processes. The CGPP established a new, two-year long-term planning process that includes a six-stage framework of data collection and scenario development, multiple system studies, and transmission solutions development and review, culminating in an initial report with recommended system investments by January 2026, for NYPSC consideration. The CGPP just finished stage one creating three scenarios and is beginning stage two to identify potential solutions and alternatives. Along with transmission planning, the CGPP also aims to enhance collaboration among interested parties and has the potential to achieve greater integration and optimization needed for transmission planning processes in New York.[114]

FIGURE 15 Coordinated Grid Planning Process Timeline[115]



F. Limited review of Advanced Transmission Technologies

As a part of CGPP, the NYPSC established the Advanced Technology Working Group (ATWG) to initially evaluate DLR, APFCs, and energy storage. In the initial order, the NYPSC stated: "We believe the ATWG's technology scouting and screening functions could identify additional options for evaluation in this CGPP cycle."[116] In January 2024, the NYPSC issued a new order directing the ATWG to consider a broader range of technologies and allowing interested parties to submit advanced technology proposals, which the group may choose to evaluate.[117] In August 2024, the ATWG hosted a webinar for interested parties on its progress, which was limited. The ATWG is moving forward with evaluations of DLR and Storage but did not give any clear timelines on the next steps.[118]

114 System Outlook at 25.

115 *Id.*

116 NYPSC, "Order Approving a Coordinated Grid Planning Process," Case 20-E-0197, August 17, 2023, at 24-25, https://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId=%7b101C058A-0000-C45D-9CD3-A87E49DF7A99%7d.

117 *See* NYPSC, "Order Establishing Procedures for the Advanced Transmission Technologies Working Group," Case 20-E-0917, January 19, 2024, https://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={B0E0228D-0000-C413-8A45-E2317EA6E16D}.

118 *See* WATT Coalition, "WATT CGPP Mid-Cycle Comments," Case 20-E-0197, October 8. 2024, https://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={90166C92-0000-CB1A-8580-A58447C08487}.

G. Slow interregional progress related to offshore wind development

NYISO has also made progress on interregional planning. In July 2024, DOE announced that ten states, including New York, have signed a MOU which "establishes a non-binding framework to coordinate enhanced interregional transmission planning and development."[119] A key component of this MOU is better coordination on the planning and development of transmission to support offshore wind generation with the states agreeing to develop a strategic action plan.[120] The states have been working with DOE on greater coordination of offshore wind transmission development for over a year. In addition, New York collaborated with the New England states on the Clean Resilience Link project, a joint application for federal funding through DOE's GRIP program.[121] DOE also identified two interregional corridors as Preliminary NIETC designations between New York, New Jersey, and Massachusetts.[122]

119 *See* MOU Collaborative on Interregional Transmission at 1.

120 *See* Utility Dive Northeastern States MOU.

121 *See* New England States Seek Federal Funding.

122 *See* NIETC Designation Process.

VIII. SPP

SUMMARY

Since the release of the 2023 ACEG report card, SPP has made several changes to its existing transmission planning processes, including continued improvements to load and resource forecasting, and integration of certain extreme weather scenarios. These changes have contributed to SPP recommending 89 transmission projects of more than $7 billion for its *2024 Integrated Transmission Planning Assessment Report (2024 ITP)*. SPP also published its third *Regional Cost Allocation Review (RCAR III)* evaluation and has continued to move forward with its Consolidated Planning Process (CPP). The intent of the CPP is to fully integrate SPP's interconnection and transmission planning process. The CPP has the potential to be a significant improvement, and the first of its kind in the country, but the process is still in its early stages, and it is not yet clear what the outcome will be. SPP has indicated it will likely file its CPP tariff revisions alongside an incremental Order No. 1920 compliance filing.

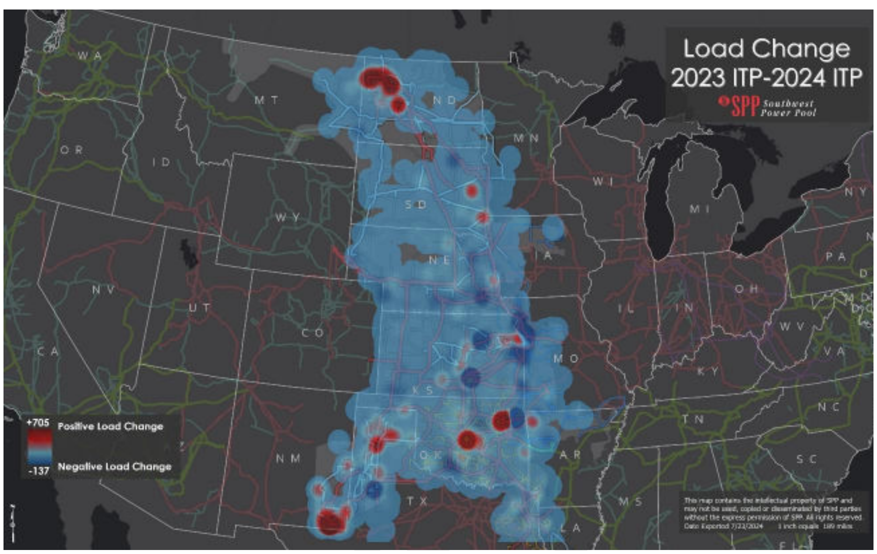
UPDATE ON SPP'S REGIONAL TRANSMISSION PLANNING AND DEVELOPMENT

A. Increased load growth and higher resource forecasts lead to historic investments in transmission

The 2024 ITP marks a significant investment in transmission for SPP. For the 2024 ITP, SPP has developed 89 new projects representing 2,333 miles of new transmission including 1,495 miles of new 345 kV and 293 miles of 765 kV transmission lines. The projects represent a $7.68 billion investment and are estimated to have a $8.90 to $9.57 in benefits for every dollar invested, which is an estimated savings of $10.55 to $11.47 on the average retail residential monthly bill. The projects in the 2024 ITP were developed as solutions to address increased load growth, growing generation forecasts, and enhance system resiliency during extreme winter weather events. SPP also found that proposed projects will help facilitate the interconnection of over 7.8 GW of new generation currently in the interconnection queue.[123]

The 2024 ITP represents a significant increase in load growth for SPP. In the past, SPP has noted that previous ITPs were likely under-forecasting future load growth as load additions and system peak loads are outpacing forecasts.[124] However, the 2024 ITP has more load growth in the second year than the entire ten-year study period of the 2023 ITP, with the trend expected to continue in the 2025 ITP. SPP is experiencing higher-than-average load growth in two specific areas, New Mexico and North Dakota due to demand from oil and gas developments.[125]

FIGURE 16 **Load Comparison of the 2023 and 2024 ITP[126]**



123 SPP, *Draft 2024 Integrated Transmission Planning Assessment Report Version 0.6*, October 7, 2024, at 1, https://www.spp.org/Documents/72515/MOPC%20Agenda%20and%20Materials_20241015_C.zip (hereinafter *Draft 2024 ITP*).

124 Cathey, C., "SPP Regional Load Forecasting Strategies," SPP, April 24, 2024.

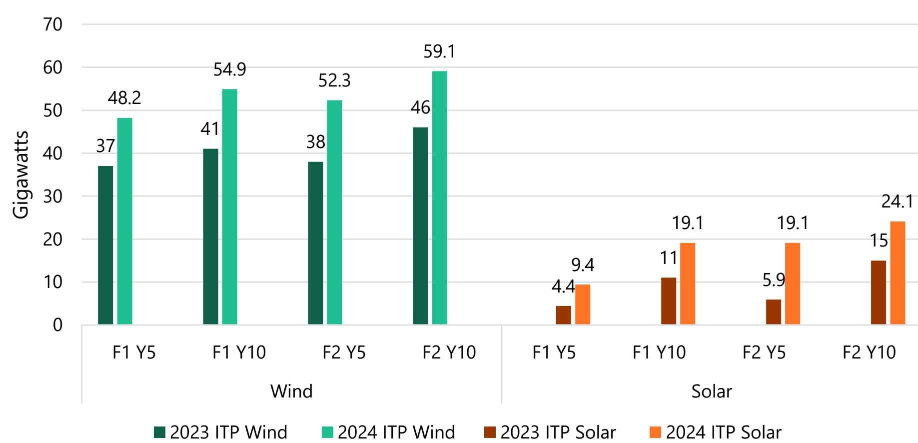
125 *Draft 2024 ITP* at 22-24.

126 *Id.* at 24.

The 2024 ITP notes that areas of concentrated load growth can severely stress the transmission system, and in some cases, the areas of concentrated load growth are more than the available transmission capacity currently available at that location. These concentrated large load additions are a major driver of the first 765 kV project SPP has ever recommended. The 2024 ITP does not include ATTs or HVDC, though the region is undergoing studies on the best way to incorporate HVDC technologies.[127]

The 2024 ITP also spent additional time addressing wind and solar generation forecasts to more closely reflect economic realities and included utility integrated resource plans, noting that past ITP reports have under-forecasted development. Both the 2023 and 2024 ITPs note that renewable development can result in significant system congestion which drove the solutions developed in both reports.[128]

FIGURE 17 **Renewable capacity comparison between the 2023 and 2024 ITPs.**[129]



B. SPP adds winter extreme weather scenarios

One of the improvements SPP made since the last report card is the incorporation of resiliency in every planning cycle and its ITP process and portfolios. SPP is currently working to finalize the 2024 ITP, which includes modeling two extreme winter weather events, Winter Storm Uri and Winter Storm Elliot, to assess the potential transmission needs for

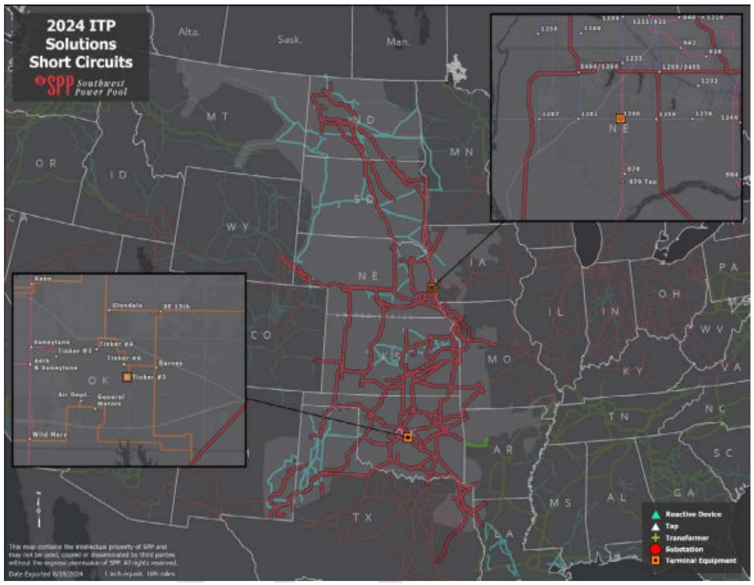
127 *See Draft 2024 ITP; See also* Brown, D., and Raheem, S., "SPP HVDC Process Review," SPP, October 15, 2024, https://www.spp.org/Documents/72515/MOPC%20Agenda%20and%20Materials_20241015_C.zip.

128 *Id.* at 25-26; SPP, *2023 Integrated Transmission Planning Assessment Report Version 1.0*, November 20, 2023, at 2-3, https://spp.org/documents/70584/2023%20itp%20assessment%20report%20v1.0.pdf (hereinafter *2023 IRP*).

129 *Draft 2024 ITP* at 26.

SPP's eastern footprint under extreme conditions.[130] The extreme winter weather scenarios are focused on southeast Kansas, southwest and southcentral Missouri, and northwest Arkansas.[131] These upgrades also support intra-regional transfers for SPP, specifically for north to south and west to east in the southern portion of the footprint.

FIGURE 18 SPP 2024 ITP Winter Weather Projects[132]



C. Third ex-post review of transmission projects finds significant benefits

SPP also completed its third Regional Cost Allocation (RCAR III) Review. The review looks at transmission projects that were in service before 2020, using 10 benefits calculated over a 40-year time horizon. The RCAR III found a 5.76:1 overall benefit-to-cost ratio for all projects in service prior to 2020. This represents an improvement over the previous 2.45:1 benefit-to-cost ratio calculated in RCAR II.[133] SPP also published its 2022 20-year Assessment in the summer of 2023. The 20-year study is information only and intended to inform other SPP planning processes. The assessment included four scenarios and identified 13 new transmission projects representing a potential $1.37-$1.55 billion investment

130 *Id.* at 24-25 and 50-56; *See also* SPP, "2024 Integrated Transmission Planning Assessment Scope," May 22, 2023, https://www.spp.org/documents/68855/2024%20itp%20assessment%20scope%20v1.3.pdf.

131 *Draft 2024 ITP* at 24-25 and 50-56; *See also* SPP, "2024 ITP Needs Assessment Posting Information," February 15, 2024, https://www.spp.org/documents/71146/2024%20itp%20needs%20assessment%20posting%20information%20(02-15-24).pdf.

132 *Draft 2024 ITP* at 21.

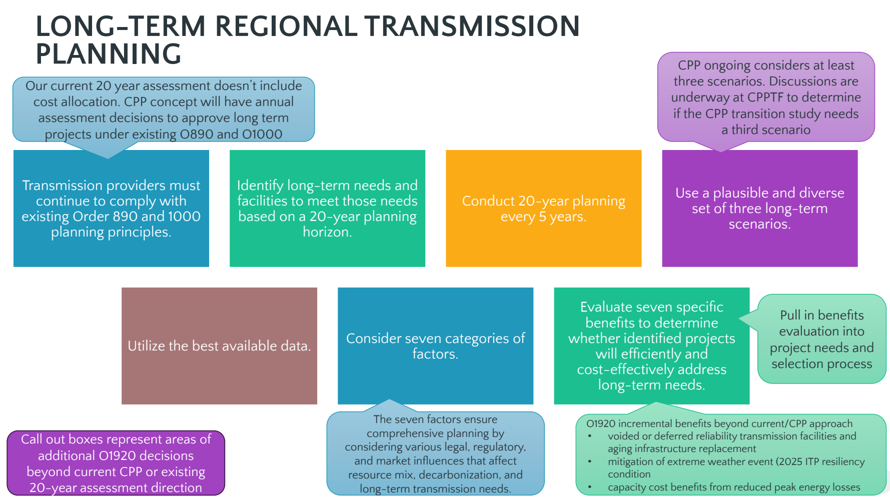
133 *See* SPP, *Regional Cost Allocation Review (RCAR III) Final Report*, January 30, 2024, at 4-5, https://www.spp.org/documents/71083/rcar%20iii%20report%20final%2020230130.pdf

with benefits ranging from $1.57 to $4.35 for every dollar invested.[134]

D. The Consolidated Planning Process looks to integrate all transmission and generation interconnection studies by next year

Underlying all these planning processes SPP has also continued to move forward with its CPP. The goal of the CPP is to completely integrate SPP's planning processes, including transmission and interconnection planning. Under the CPP, SPP plans to develop a comprehensive, long-term assessment of generation and load needs over a 20-year period, incorporating regional and subregional transmission components and needs. The next step in the CPP process are transition studies that will help the RTO switch over from current planning processes to the CPP.[135] Part of the transition study work will be to set an entry fee for new service customers as a required contribution to network improvements.[136] At the July 2024 meeting, SPP indicated the region plans to file associated tariff changes in concert with Order 1920 compliance filings in the summer of 2025. Efforts to comply with Order No. 1920 will begin in October 2024 along with the State Engagement Period.[137]

FIGURE 19 Comparison of SPP's current planning processes with Order No. 1920 requirements[138]



134 SPP, *2022 20-year Assessment Report Version 1.0*, July 31, 2023, at 7-11, https://www.spp.org/documents/69814/2022%2020-year%20assessment%20report%20v1.0.pdf.

135 SPP, *Consolidated Planning Process (CPP) Phase 1*, December 13, 2023, at 3-9 and 32-34, https://www.spp.org/Documents/71793/SCRIPT%20C1%20CPP%20Phase%201%20Assessment%20Inclusion%20and%20Transition%20Plan%20Recommendation%20Report%20Jan%202024%20MOPC%20Approved.docx

136 *See* SPP, "Entry Fee Framework Policy Direction Recommendations," April 16, 2024, https://www.spp.org/Documents/71794/CPPTF%20Entry%20Fee%20Framework%20Recommendation%20Final%20April%202024%20Approved.docx.

137 *See* SPP, "5. FERC Order 1920," July 7, 2024, https://www.spp.org/Documents/71991/CPPTF%20Meeting%20Material%2020240722.zip.

138 *Id.* at 3.

E. Limited progress on interregional transmission planning as JTIQ moves forward

SPP and MISO continue to move forward with their JTIQ portfolio. The regions have agreed to a Joint Operating Agreement and cost allocation methodology, which have both been filed at FERC for approval.[139] However, not all parties in SPP and MISO were supportive of the cost allocation structure which proposes to allocate costs solely to developers.[140] The JTIQ portfolio was also awarded $464 million in the first round of DOE GRIP funding announced in October 2023.[141] Both regions have indicated there will likely be a second round of planning. As discussed in the original report, this is a good step forward in aligning processes to work on joint planning and will facilitate the connection of 28-53 GW of new generation, but the process falls short of true, optimized interregional planning which would consider a more holistic set of transmission benefits beyond simply easing the interconnection process. However, cost allocation for interregional transmission will require improvements to comply with beneficiary-pays principles. In addition, SPP and MISO have announced they are engaging in a new planning approach at their seam in 2025. The study is intended to identify near-term upgrades that incrementally enhance transfer capability, similar to the PJM study, but may also allow for the identification of projects with multiple benefits.[142]

139 *See generally* tariff revisions and JOA filings from SPP and MISO in FERC Docket Nos. ER24-2797-000, ER24-2798-000, ER24-2871-000, ER24-2825-000.

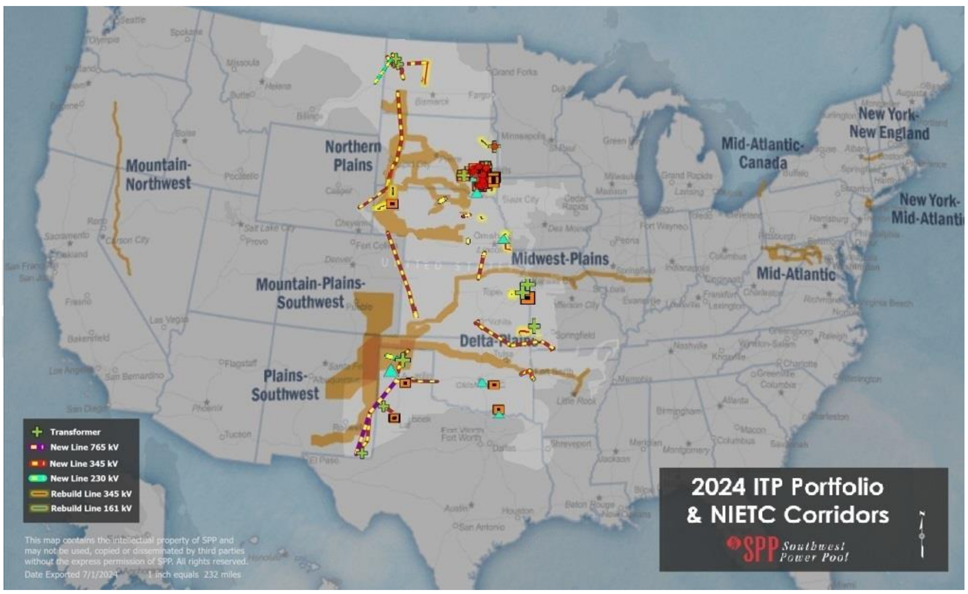
140 *See* Protest of the Clean Energy Associations.

141 *See* GDO JTIQ Award.

142 *See* SPP-MISO CSP.

SPP also received half of the preliminary NIETC corridor designations from DOE, reflecting the significant value and need for intra-regional and interregional transmission in the region identified by the 2024 ITP.[143] In its 2024 ITP, SPP highlights the fact that several of its proposed transmission lines fall within NIETC corridors and may be eligible for additional federal funding or permitting tools to help accelerate the construction of the projects.

FIGURE 20 **2024 ITP portfolio and preliminary DOE NIETC corridors**[144]



143 *See* NIETC Designation Process.

144 Draft 2024 ITP at 12.

IX. Southeast

SUMMARY

At the regional planning level, there have been no apparent reforms or improvements to the regional Order No. 1000 planning processes conducted by the Southeastern Regional Transmission Planning (SERTP) process, the South Carolina Regional Transmission Planning (SCRTP) process, and the Florida Reliability Coordinating Council (FRCC). The regions have continued to use the same planning process described in the 2023 report card. However, there have been some reforms and changes at the utility level as the region has faced significant load growth. The local transmission planning process in North and South Carolina, known as Carolinas Planning Collaborative, has been framed as a local, proactive, multi-value planning process, but the initial study proposals appear very incremental and fall short of true proactive, multi-value planning. The Tennessee Valley Authority (TVA) has also indicated it will begin a transmission planning process as a part of its Integrated Resource Plans. For compliance with Order No. 1920, SCRTP and SERTP have announced that they will merge their planning process as well as a timeline for input from interested parties.

UPDATE ON THE SOUTHEAST REGION'S TRANSMISSION PLANNING AND DEVELOPMENT

There are three Order No. 1000 regional planning entities in the Southeast: SERTP, SCRTP, and FRCC. Since the release of the report card in 2023 all three entities have not made changes to their existing regional transmission planning processes.[145]

A. No changes to regional planning in the Southeast

SERTP has not made changes to its transmission planning methods since the release of the 2023 report card. SERTP did not select any public policy scenarios for study in the 2024 planning cycle, but preliminary study results for the scenarios SERTP selected for the 2024 economic studies continue to show potential opportunities to develop multi-value transmission projects, though further evaluation is necessary.

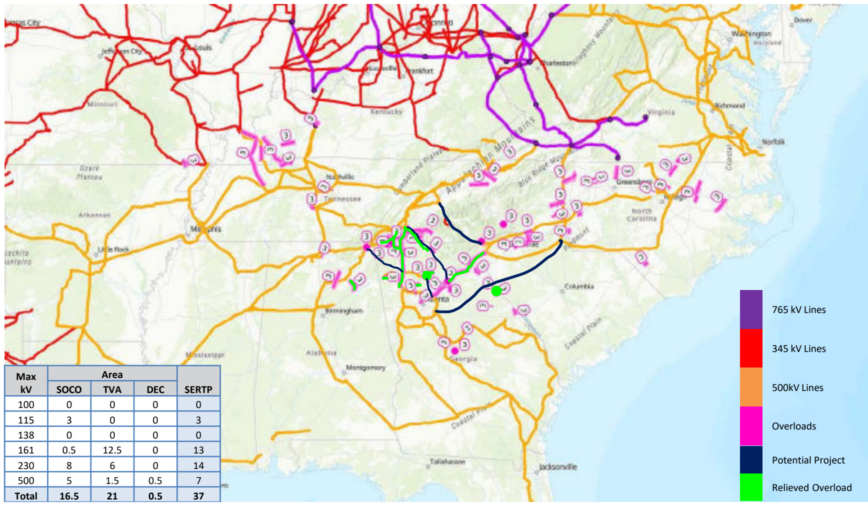
For example, in the 2024 economic studies, SERTP evaluated the transfer of 10 GW of generation from MISO to Southern Company. This transfer resulted in a substantial number of violations requiring significant upgrades between the Carolinas and Southern Company to address the violations.[146] This same area was also identified in the preliminary results of the North American Electric Reliability Corporation (NERC) *Interregional Transfer Capability Study* (ITSC) (discussed further below) as a region with potentially a need for up to 4000 MW in prudent interregional transmission additions.[147] The results in both studies are preliminary, and more evaluation of the benefits and costs of potential solutions is needed, but the preliminary results show the potential for there to be a transmission solution that could potentially provide both reliability and economic benefits for the Southeast.

145 *See generally* SCRTP website, accessed October 16, 2024, https://www.scrtp.com/meeting-archives.html; *See also* FRCC website, accessed October 16, 2024, https://www.frcc.com/SitePages/Homepage1.aspx.

146 SERTP, "SERTP – 3rd Quarter Meeting," September 24, 2024, https://www.southeasternrtp.com/docs/general/2024/2024_SERTP_3rd_Quarter_Meeting_Presentation.pdf (hereinafter SERTP 3rd Quarter Meeting).

147 NERC, "Interregional Transfer Capability Study Advisory Group Meeting," August 29, 2024, at 28-29, https://www.nerc.com/pa/RAPA/ITCS/ITCS_AG_Presentation_20240827.pdf (hereinafter NERC ITCS Preliminary Results).

FIGURE 21 Potential Strategic Solution 1 - P1 for 10,000 MW transfer from MISO North to Southern Company[148]



Max kV	Area			SERTP
	SOCO	TVA	DEC	
100	0	0	0	0
115	3	0	0	3
138	0	0	0	0
161	0.5	12.5	0	13
230	8	6	0	14
500	5	1.5	0.5	7
Total	**16.5**	**21**	**0.5**	**37**

Despite no changes to existing transmission planning processes since 2023, all three regions will need to make planning reforms to comply with Order No. 1920. SERTP and SCRTP started that process by announcing in September 2024 that the two planning regions will be merging to comply with Order No. 1920. At the same time, SERTP also announced a process to engage with interested parties on the development of the compliance filing. The timeline includes education on Order No. 1920 requirements by SERTP in November 2024, presentations by interested parties in December 2024 and January 2025, and initial transmission provider proposals in March through May 2025, with an opportunity for interested parties to provide feedback on the proposals. The Transmission Providers in SERTP and SCRTP plan to begin the engagement period with Relevant State Entities in a separate non-public process from November 2024 to April 2025.[149]

B. Opportunities in local transmission planning to develop more proactive, multi-value plans

Utilities in the Southeast have been experiencing some of the largest load growth in the country, which has been reflected largely through the development of new generation in their IRPs.[150] However, some utilities have transmission planning developments

148 SERTP 3rd Quarter Meeting at 26.

149 SERTP, "2024 SERTP Q3 Policy Announcements," September 24, 2024, at 2-4, https://www.southeasternrtp.com/docs/general/2024/2024_SERTP_Q3_Policy_Announcements.pdf.

150 *The Era of Flat Power Demand is Over* at 17, 18.

that show promise and include recent large load growth in their local transmission planning processes. For example, in the Carolinas, Duke Energy has spearheaded reforms to the local transmission planning process in an attempt to create a more proactive, multi-value transmission plan.[151] The process, which is looking to study Multi-Value Strategic Transmission (MVST) Projects, has so far had good participation from interested parties and includes updated load forecasts. However, there are some key pitfalls in the process that may prevent Duke from achieving its stated goals. In the proposed study plan, the current study horizon is only 10 years, which will likely prevent longer lead time projects from being identified and built. In addition, the current plan does not include detailed enough economic modeling or an iterative process with generation buildout to create a fully optimized plan that would deliver the lowest cost to Carolina customers.[152] Another potential development at the subregional level that could improve transmission planning in the Southeast is a preliminary indication from TVA to potentially incorporate transmission planning into its Integrated Resource Plan.[153]

151 *See* Carolinas Transmission Planning Collaborative (CTPC), "Multi-Value Strategic Transmission Planning," January 1, 2024, http://www.nctpc.org/nctpc/document/REF/2023-11-10/Multi-Value%20Strategic%20Transmission%20Planning%20Process%20draft%2011-9-2023.pdf.

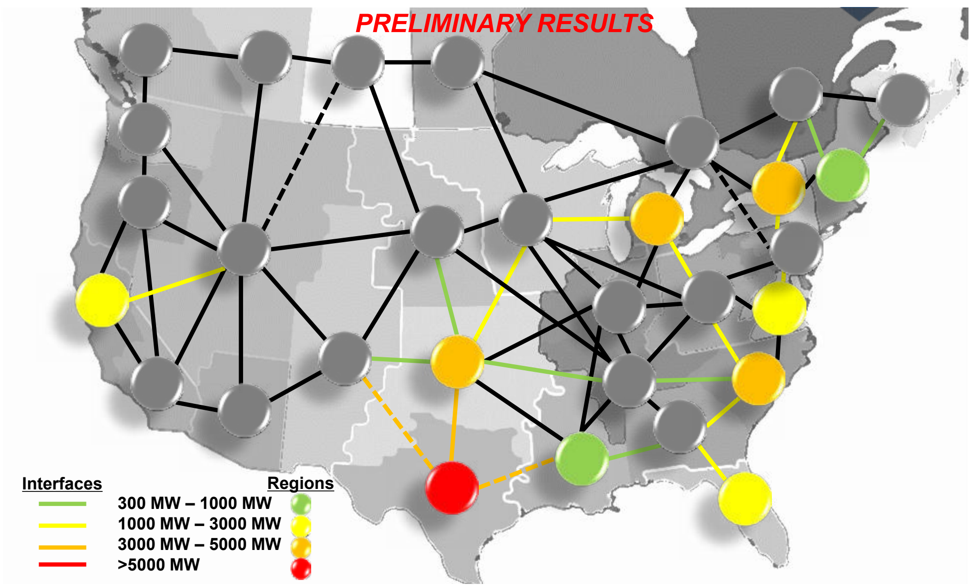
152 *See* CTPC, "2024 Multi-Value Strategic Transmission (MVST) Study," August 16, 2024, https://carolinastpc.org/media/reference/2024/08/19/2024_CTPC_MVST_Study_Scope_08_16_2024_Clean.pdf; *See also* "Joint Comments on MVST Study Proposals," August 26, 2024, https://carolinastpc.org/media/reference/2024/09/24/Aug_26_2024__Joint_Comments_on_MVST_Scenarios.pdf.

153 Tennessee Valley Authority, "2025 Draft Integrated Resource Plan Volume 1," September 2024, at 1-7, https://tva-azr-eastus-cdn-ep-tvawcm-prd.azureedge.net/cdn-tvawcma/docs/default-source/environment/environmental-stewardship/integrated-resource-plan/2025/draft-2025-irp-volume-1-092324.pdf?sfvrsn=26f01b64_1.

C. Preliminary results from NERC interregional study find needs in the Southeast

The Southeast continues to have very limited interregional transmission planning. Moreover, preliminary results from the NERC ITCS presented at the August 2024 Advisory Group meeting found that a couple of regions in the Southeast will require additional investments in interregional transmission to maintain reliability.[154]

FIGURE 22 Preliminary Interregional Transmission Needs[155]



154 *See* NERC, "Interregional Transfer Capability Study (ITCS)," accessed October 16, 2024, https://www.nerc.com/pa/RAPA/Pages/ITCS.aspx.

155 NERC ITCS Preliminary Results at 28.

X. ERCOT

SUMMARY

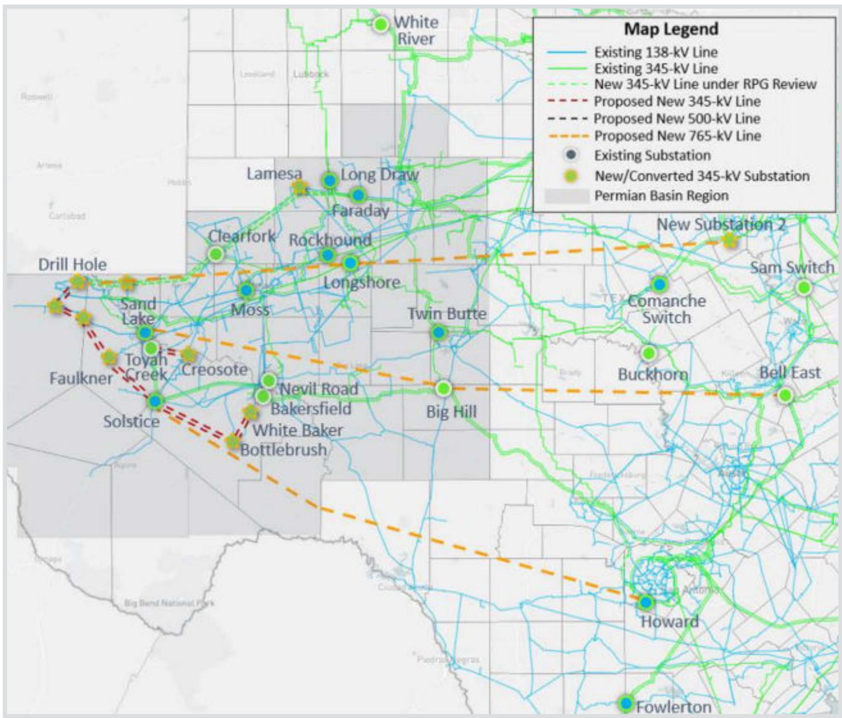
In the 2023 report card, ERCOT had one of the lower grades for transmission planning. The region needs to improve its high-capacity transmission planning as it is facing some of the most significant load growth in the country and extreme weather will continue to stress a system that is islanded from its neighbors. This combination of load growth and extreme weather spurred legislation requiring reforms to transmission planning by the Public Utilities Commission of Texas (PUCT) and ERCOT. Many of these new processes are still in development and it will likely take a few years to fully see the impact. The region would also likely see benefits from greater integration and coordination between these processes. FERC does not have jurisdiction in ERCOT, so the region does not have to comply with Order No. 1920 requirements. The region is advancing a roughly $12 billion transmission plan to address load growth in the Permian Basin.

UPDATE ON ERCOT’S TRANSMISSION PLANNING AND DEVELOPMENT

A. Load growth is driving significant new investments in transmission

In response to House Bill 5066, from the 88th Texas Legislature, ERCOT is in the process of developing a transmission plan to maintain reliability and also connect significant new loads in the Permian Basin in west Texas, primarily from new oil and gas and data center loads. A draft plan was released in July 2024 which identified new 345 kV, 500 kV, or 765 kV facilities needed in 2030 and 2038. The different voltage plans estimated new transmission investments ranging from $12.95 billion to $15.32 billion to accommodate a total of 27 GW of new load, including 15 GW from new oil and gas load and 12 GW from new data center and other loads.[156]

FIGURE 23 765 kV path options in 2038[157]



The plan to help bring more power into west Texas represents almost double the transmission investment from the Texas Competitive Renewable Energy Zones (CREZ) project which were developed more than a decade prior to move new generation out of north and west Texas. The PUCT approved the plan in September 2024 but delayed a decision until the spring of 2025 on whether to build 765 kV transmission lines or use 345 kV to allow for additional evaluation.[158] ERCOT has increasingly been interested in using 765 kV or HVDC transmission lines to address grid needs. In 2024, ERCOT held multiple presen-

156 Electric Reliability Council of Texas (ERCOT), *Permian Basin Reliability Plan Study,* July 2024, at ii-xi, https://interchange.puc.texas.gov/Documents/55718_17_1414013.PDF (hereinafter *Permian Basin Reliability Plan*).

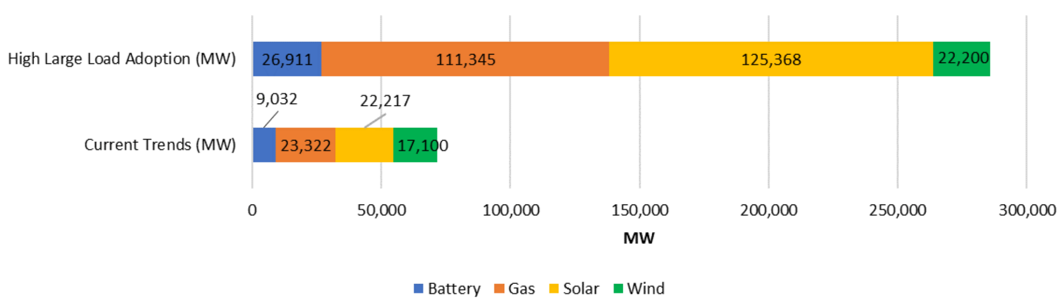
157 *Id.* at ix.

158 Public Utility Commission of Texas (PUCT), "Filings for Case 55718," accessed October 16, 2024, https://interchange.puc.texas.gov/search/filings/?UtilityType=A&ControlNumber=55718&ItemMatch=Equal&DocumentType=ALL&SortOrder=Ascending.

tations and a workshop on 765 kV and HVDC lines, and in the *2023 RTP Economic Study* evaluated four potential HVDC projects.[159]

Load growth outside of the Permian Basin is also impacting ERCOT's *2024 Regional Transmission Plan* (RTP) and its *2024 Long-Term System Assessment* (LTSA). HB 5066 allowed ERCOT to consider prospective loads identified by transmission providers, even if the load does not have financial commitments or a signed interconnection agreement, to better capture changes in large loads. In the 2024 RTP, ERCOT is expecting approximately 150 GW of load by 2030 but only 120 GW of available generation.[160] To address this resource gap and the nature of the loads, ERCOT is planning to model "Generation Hubs," which will result in an additional 11 GW of dispatchable generation not in the interconnection queue.[161] ERCOT is also evaluating Extra High-Voltage options as part of its transmission solutions in the 2024 RTP.[162] In the LTSA, ERCOT is also evaluating a "High Large Load Adoption Scenario." Preliminary results from this scenario find that by 2039, ERCOT could have an additional 70,000 MW of new load, almost doubling the current peak. To serve this new load ERCOT estimates it would need to add 285,000 MW of new resources, including 125,000 MW of solar, 110,000 MW of natural gas generation, 27,000 MW of storage, and 22,000 of wind.[163]

FIGURE 24 LTSA 2039 Capacity Expansion Additions[164]



159 *See* ERCOT, "2023 RTP Economic Study Results," January 17, 2024, https://www.ercot.com/files/docs/2024/01/16/2023%20RTP%20Economic%20Study%20Results_v2.0.pdf; *See also* ERCOT, "EHV 765 kV Vendor Workshop, September 18, 2024, https://www.ercot.com/calendar/09182024-EHV-765-kV-Vendor; *See also* ERCOT, "RPG Meeting," October 16, 2024, https://www.ercot.com/calendar/10162024-RPG-Meeting.

160 ERCOT, "2024 RTP – Generation Assumptions Update," April 2024, at 2, https://www.ercot.com/files/docs/2024/04/08/2024_RTP_Generation_Assumptions_Update_April_2024_RPG.pdf

161 ERCOT, "2024 RTP Update," May 2024, at 4-6, https://www.ercot.com/files/docs/2024/05/14/2024_RTP_Update_May_2024_RPG.pdf.

162 ERCOT, "ERCOT Extra-High Voltage (EHV) Infrastructure Initiative Introduction," June 2024, at 5, https://www.ercot.com/files/docs/2024/06/10/ERCOT_EHV_Infrastructure_Initiative_Introduction_June_2024_RPG.pdf.

163 ERCOT, "2024 Long-Term System Assessment (LTSA): High Large Load Adoption Scenario," August 13, 2024, at 5-8, https://www.ercot.com/files/docs/2024/08/08/2024%20Long-Term%20System%20Assessment%20(LTSA)%20High%20Large%20Load%20Adoption%20Scenario.pdf.

164 *Id.* at 8.

B. ERCOT updates economic planning process

Another key requirement is found in in Senate Bill (SB) 1281 from the 87th Texas Legislature to develop a new congestion cost savings test to evaluate the savings a transmission line would create for ERCOT energy consumers during the economic planning process. As discussed in the initial report card, ERCOT's production cost savings test is extremely narrow and has resulted in almost no projects being selected over the past decade, despite rising congestion costs in the region.[165] While the new test is being developed, the PUCT ordered ERCOT to immediately resume analysis of economic projects using the pre-existing generator revenue test and the production cost savings test. A transmission line that passes either test is considered economically viable and may be approved. ERCOT hired E3 to develop the new test and E3 recommended the System-Wide Gross Load Cost Test, which determines the change in the energy cost charged to customers, in this case, load. The energy cost itself is calculated based on the sum of energy used in each location multiplied by the location price for the customers/load. E3 recommended this System-Wide Gross Load Cost Test to ERCOT in September 2023,[166] with the official study being published in May 2024.[167] The test will likely be approved by the end of 2024 with the test being used in the *2024 RTP Economic Study* for information only.[168]

C. Two new extreme weather scenarios

SB 1281 also required resiliency to be added as a factor considered in transmission planning.[169] To address this, ERCOT is working on the Grid Reliability and Resiliency Assessment, with the first draft of the assessment expected in December 2024. The study will directly examine extreme weather scenarios and potential transmission solutions. The two extreme weather scenarios are a hurricane, which is being developed with assistance from Argonne National Labs,[170] and extreme cold.[171]

165 2023 Congestion Report at 12.

166 Energy + Environmental Economics (E3), "Congestion Cost Savings Test Discussion Presentation to ERCOT PLWG," September 19, 2023, at 24, https://www.ercot.com/files/docs/2023/09/15/E3_ERCOT_Congestion_Cost_Savings_Test_Study_2023-09-17.pdf.

167 *See* E3, *Congestion Cost Savings Test for Economic Evaluation of ERCOT Transmission Projects*, prepared for ERCOT, March 2024, https://www.ercot.com/files/docs/2024/05/23/E3_ERCOT_Congestion_Cost_Savings_Test_for_Economic_Transmission_Report_March_2024.pdf.

168 ERCOT, "2024 RTP Economic Study Preliminary Results," September 25, 2024, at 2, https://www.ercot.com/files/docs/2024/09/24/2024%20RTP%20Economic%20Study%20Results_20240925.pdf.

169 Texas State Legislature, SB 1281, effective June 16, 2021, https://capitol.texas.gov/billlookup/text.aspx?LegSess=87R&Bill=SB1281.

170 *See* Argonne National Laboratory and ERCOT, "High Level Overview of Argonne National Lab (ANL) Study on Potential Severe Weather Event Scenarios," August 13, 2024, https://www.ercot.com/files/docs/2024/08/12/ANL%20Potential%20Severe%20Weather%20Event%20Study_08132024RPG%20meeting.pdf.

171 ERCOT, "2024 Grid Reliability and Resiliency Assessment Scope," June 2024, at 6, https://www.ercot.com/files/docs/2024/06/10/2024_Reliability_and_Resiliency_Assessment_Scope_June_2024_RGP.pdf

D. No progress on interregional transmission planning and development

Beyond transmission planning, there has been little movement on interregional transmission and the two proposed interregional merchant transmission lines. Pecos West is an approximately 280-mile, 525 kV HVDC line between Bakersfield in Pecos County, Texas, and El Paso, Texas, providing a connection between ERCOT and the western transmission system being developed by Grid United.[172] Southern Spirit Transmission is an approximately 320-mile, 525 kV, HVDC transmission line connecting ERCOT and the southeastern transmission grids being developed by Pattern, which recently received support from the TFP.[173] Since the 2023 report card, the PUCT has asked for modeling on the impact and benefits Southern Spirit would have had if it had been in service on September 6, 2023, the last time ERCOT was in emergency operations.[174]

172 Grid United, "Pecos West Intertie," accessed October 16, 2024, https://pecoswest.com/.

173 Pattern Energy, "Southern Spirit Transmission," accessed October 16, 2024, https://patternenergy.com/projects/southern-spirit-transmission/.

174 Kleckner, T., "Texas PUC Sends ESR Change back to ERCOT," January 24, 2024, https://www.rtoinsider.com/69273-texas-puc-sends-esr-change-ercot/.

XI. The West

SUMMARY

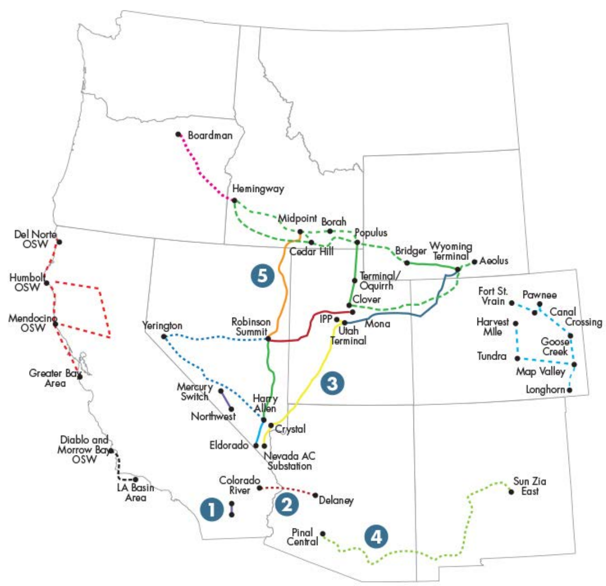
Across the Western Interconnect, several initiatives have sprung up to improve transmission planning that appear promising. However, it is not yet clear what will be the most effective effort, or if any of the processes will be sustainable and Order No. 1920-compliant in the long run. At the state level, some of the most effective large-scale transmission development in the country continues to move forward. At least one of the processes has stated it is not an Order No. 1920 compliance process, and the two regional planning entities in the West outside of CAISO have held limited public discussions on compliance with the rule.

THE WEST

A. WestTEC is a promising new interconnection-wide, proactive, scenario-based, multi-value planning effort

A potentially key planning development in the west has been the creation of the Western Transmission Expansion Coalition (WestTEC), which is a voluntary, west-wide initiative to develop an actionable 20-year transmission study. Especially in regions where public power plays a large role but is not subject to FERC jurisdiction or the requirements in Order No. 1920, it is worth noting that many public power entities are participating in WestTEC. Further, after FERC's decision in WestConnect, which would require any public power entity participating in a FERC jurisdictional planning process to also be subject to cost allocation, it is more valuable than ever to have a comprehensive planning process that does not require mandatory assumption of costs under federal jurisdiction.[175] The initiative has brought together interested parties from all sectors to collaboratively develop a proactive, scenario-based, multi-value transmission analysis. The analysis is currently scheduled to happen over a two-year horizon with a 10-year plan expected to be finalized in the summer of 2025 and the 20-year plan expected in the fall of 2026. While the planning process is still in the early stages, it is promising that the group expects to have multiple scenarios that account for load growth and variation, as well as resource forecasts that account for state laws and various company and utility goals.[176] The analysis itself will include an extreme weather scenario and develop a portfolio of transmission solutions for which benefits very similar to Order No. 1920 will be quantified. However, WestTEC is not addressing questions of cost allocation, and the process is non-binding, meaning that if a highly valuable project is identified it is not clear what entity will be working on developing the solution and it may not get built at all.[177]

FIGURE 25 **Significant Transmission Projects in the Western Interconnection**[178]



175 *See* generally, Order on Remand, Directing Further Compliance, and Establishing a Show Cause Proceeding, FERC 189 ¶ 61,028 (October 17, 2024), https://www.ferc.gov/media/e-11-er13-75-013.

176 *See* Western Transmission Expansion Coalition (WestTEC), "Western Transmission Expansion Coalition Study Plan," August 27, 2024, https://www.westernpowerpool.org/private-media/documents/WestTEC_Study_Plan_-_V5_Final.pdf.

177 WestTEC, "Western Transmission Expansion Coalition "WestTEC" Public Webinar," July 23, 2024, at 5, 11, https://www.westernpowerpool.org/private-media/documents/WestTEC_Public_Webinar_7.23.pdf.

178 CAISO Taking the Long View.

B. WECC updates data with a focus on extreme weather

The Western Electricity Coordinating Council (WECC) has also been working on a few improvements. WECC has been collecting data to develop 20-year anchor dataset cases that include extreme weather. This is a key for improving transmission planning in the west, as both NorthernGrid and WestConnect rely on WECC for the base cases in their planning processes. In addition, as a part of the 2023 Reliability Assessment, WECC conducted a 20-year assessment for the first time that included extreme cold, heat, and a high load-growth scenario.[179]

Within the interior west, there are two Order No. 1000 regional planning entities, WestConnect and NorthernGrid. Both regions operate on a biannual transmission planning cycle, and there have been limited reforms to either planning process since the 2023 report card release.

NorthernGrid

A. New economic studies, but no significant planning reforms

NorthernGrid covers the Pacific Northwest through Idaho, Montana, Wyoming, and Utah, as well as Nevada. The region is currently collecting data for its 2024-2025 planning cycle, and published its draft study scope in October 2024. Alongside its biannual transmission planning process, NorthernGrid conducts information-only economic studies at the request of interested parties. These studies have so far included the evaluation of offshore wind in Oregon and a pumped storage hydro project in Wyoming and Oregon.[180] NorthernGrid has also approved an economic study request for the North Plains Connector and Pumped Hydro Storage in Oregon.[181] The overall planning process remains largely a compilation of the member utilities' local transmission plans, and the planning entity has not publicly indicated how it will comply with Order No. 1920 requirements, though it has announced it will begin the State Engagement Period on November 1, 2024.[182]

179 *See* Western Electric Coordinating Council (WECC), *Year 20 Transmission Trends Assessment*, June 2024, https://www.wecc.org/wecc-document/2406; *See also* WECC, *Reliability Assessments*, accessed October 16, 2024, https://www.wecc.org/program-areas/reliability-planning-performance-analysis/reliability-assessments.

180 *See* NorthernGrid, *Economic Study Request Offshore Wind in Oregon,* July 21, 2023, https://www.northerngrid.net/private-media/documents/2022_ESR_OSW_Approved.pdf; *See also* NorthernGrid, *Economic Study Request Pumped Storage Hydro in Wyoming,* July 21, 2023, https://www.northerngrid.net/private-media/documents/2022_ESR_PSH_Approved.pdf; *See also* NorthernGrid, *Economic Study Request Pumped Storage Hydro in Oregon*, April 19, 2024, https://www.northerngrid.net/private-media/documents/ESR_OSW_PSH_Final.pdf.

181 NorthernGrid, "NorthernGrid 2024 Economic Study Request Decision," May 23, 2024, https://www.northerngrid.net/private-media/documents/ESR_Decision_2024.pdf.

182 NorthernGrid, "FERC 1920 Engagement," October 1, 2024, https://www.northerngrid.net/private-media/documents/NorthernGrid_Website_Posting_-_Notice_of_FERC_Order_1920_State_Engagement_Period.pdf.

B. BPA proposes to develop more high-capacity transmission

The biggest transmission owner and operator in the region, Bonneville Power Administration (BPA), has proposed significant transmission investments in the last two years, despite only building 153 miles of 500 kV lines in the 2010s.[183] In its last two Transmission Service Request planning cycles, BPA has identified over $5 billion in transmission investments to connect more than 20 GW of new resources.[184] As a part of its 2023 transmission service cluster study process BPA identified projects on its system that may have regional significance,[185] and in October 2024 proposed 13 new projects that are projected to cost $3 billion.[186] This renewed focus on transmission development is primarily due to increased demand for transmission service from new generation and anticipated load growth in the Pacific Northwest of more than 30% in the next decade.[187] BPA has also been very involved in the WestTEC transmission planning process.

C. Utilities and independent developers in the Northwest continue to advance significant transmission investments

Outside of BPA, utilities in the region have a significant amount of transmission development underway, and new merchant and regulated utility lines driven by load growth and the need for new generation are being proposed and developed. PacifiCorp, which is expecting an almost 4 GW (33%) increase in peak load over the next 20 years, continues its construction of the Gateway Energy Projects and Boardman to Hemingway Transmission Line. NV Energy is working on the Greenlink Projects.[188] Both SWIP North and Cross-Tie transmission projects in the NorthernGrid planning region have received cost allocation through CAISO with the Subscriber PTO. In addition, Portland General Electric (PGE) has signed a non-binding MOU with Grid United and ALLETE that is expected to involve a 20 percent ownership in the North Plains Connector which will provide PGE with access to new resources in the Eastern Interconnect, providing significant resource adequacy

183 Northwest Power and Conservation Council, "Memorandum to Council Members Re: Bonneville's Evolving Grid Effort and 2023 Cluster Study," August 8, 2023, at 19, https://www.nwcouncil.org/fs/18429/2023_08_3.pdf.

184 Bonneville Power Administration (BPA), "TSR Study and Expansion Process (TSEP) 2022 Cluster Study Results," December 15, 2022, at 6-7, https://www.bpa.gov/-/media/Aep/transmission/atc-methodology/2022-cluster-study-results-overview-customer.pdf; BPA, "TSR Study & Expansion Process (TSEP) Update Summary of the 2023 Cluster Study," February 29, 2024, at 24-27, https://www.bpa.gov/-/media/Aep/transmission/atc-methodology/02-29-24-2023-cs-findings-summary-part1-external.pdf.

185 BPA, "Evolving Grid Update on Transmission Activities," May 16, 2024, at 46-52, https://www.bpa.gov/-/media/Aep/transmission/transmission-business-model/05-16-24-meeting-materials.pdf

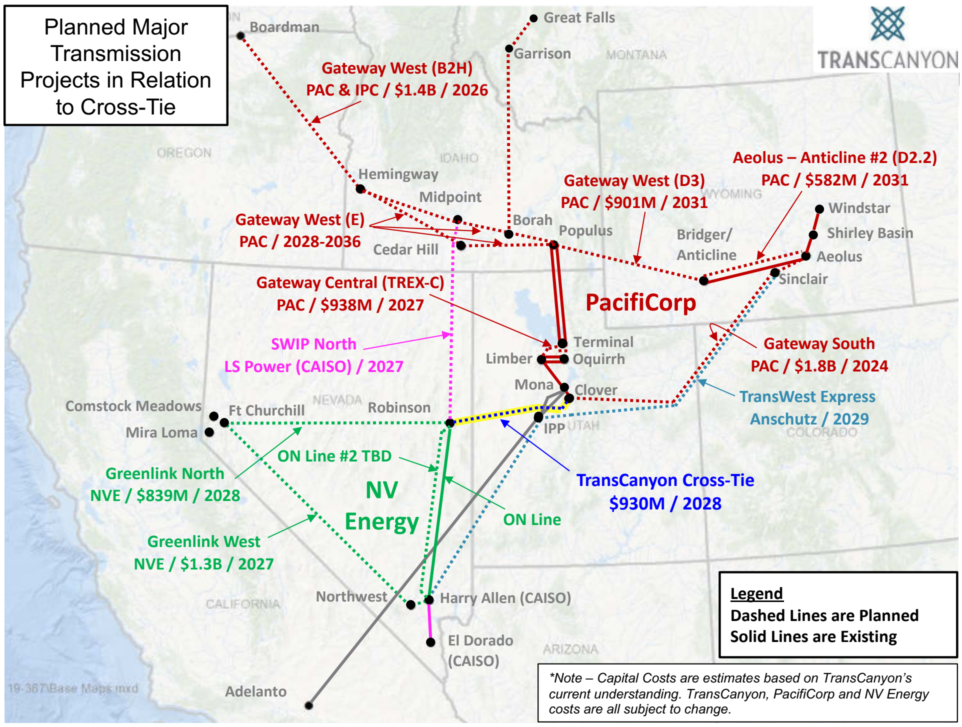
186 BPA, "Evolving Grid Projects (EGP) 2.0 Summaries," October 15, 2024, https://www.bpa.gov/-/media/Aep/transmission/transmission-business-model/EGP-20-Proposed-Project-Summariesfinal-101524.pdf.

187 PNUCC, *Northwest Regional Forecast of Power Loads and Resources*, May 2024, at 4, https://www.pnucc.org/wp-content/uploads/2024-PNUCC-Northwest-Regional-Forecast-final.pdf; *See also* BPA, *2024 Pacific Northwest Loads and Resources Study*, August 2024, at 29 https://www.bpa.gov/-/media/Aep/power/white-book/2024-white-book.pdf.

188 See additional details on the transmission projects in ACEG, *Ready-To-Go Transmission Projects 2023*, at 7-23, https://cleanenergygrid.org/wp-content/uploads/2023/09/ACEG_Transmission-Projects-Ready-To-Go_September-2023.pdf; PacifiCorp, "2025 Integrated Resource Plan Public Input Meeting," June 26-27, 2024, at 12-18, https://www.pacificorp.com/content/dam/pcorp/documents/en/pacificorp/energy/integrated-resource-plan/2025-irp/PacifiCorp_2025_IRP_PIM_June_26-27_2024.pdf.

benefits.[189] Multiple projects in the west have also received funding and support from the federal government through the TFP and recognition in preliminary identifications as NIETCs.

FIGURE 26 **Figure developed by Transcanyon and provided to NorthernGrid on planned major transmission projects in relation to Cross-Tie**[190]



WestConnect

A. New extreme weather scenarios, but no significant planning reforms

WestConnect generally covers planning in the southwest and some of the interior west and also operates on a biennial planning cycle. Overall, the planning process remains largely a compilation of the member utilities' local transmission plans, though exemptions for non-FERC jurisdictional utilities continue to limit the effectiveness of the regional transmission planning process.

189 Portland General Electric, "PGE joins Grid United and ALLETE in 3,000 megawatt east-west transmission line," May 28, 2024, https://portlandgeneral.com/news/2024-05-pge-joins-grid-united-and-allete-in-east-west-transmission-line.

190 NorthernGrid, "Western Transmission Projects," March 27, 2024, https://www.northerngrid.net/private-media/documents/Western_Transmission_Projects_Map_2024-03-07.pptx.

For its 2024-2025 study plan, WestConnect did include some incremental improvements to its scenarios studied in the economic planning process. The additions include an Extreme Cold Weather scenario and a Renewable Resource Adequacy scenario that will be evaluated on a 20-year timeline. However, these scenarios are informational only, and do not feed into the regional transmission needs that may be identified in the plan, though WestConnect notes the scenarios could inform future planning cycles.[191]

For Order No. 1920 compliance, WestConnect has presented very little publicly indicating how it will comply with the requirements. It has indicated that TOs are working on compliance and that individual utilities in each state are responsible for outreach to and coordination of input from state public service commissions.[192] WestConnect and most of its entities are also participating in the WestTEC planning process.

B. States, utilities, and independent developers in the southwest continue to advance significant transmission investments

Similar to the Pacific Northwest, states and utilities in the Southwest are playing a significant role in the planning and development of transmission. Xcel, which recently announced it had 6.7 GW of data center requests, is continuing construction on the Colorado Power Pathway.[193] Colorado's Electric Transmission Authority is also in the process of completing a Transmission Capacity Expansion Study, which is a 20-year study to determine the transmission needed to meet the state's energy needs.[194] In New Mexico, the Public Service Company of New Mexico is currently conducting a 20-year transmission study which includes a 20-30% increase in peak load to determine the transmission needs beyond its current IRP and 10-year transmission plan, with a final plan expected at the end of 2024.[195] Also in New Mexico, ground was broken in 2023 on the SunZia transmission line, the third transmission project to be developed with support from the New Mexico Renewable Energy Transmission Authority (NM RETA). In addition, the southwest region has several merchant transmission projects that have been proposed, with three merchant lines (RioSol, North Path, and Lucky Corridor) being supported by NM RETA.[196]

191 WestConnect, *WestConnect Regional Transmission Planning 2024-25 Planning Cycle Regional Study Plan*, March 20, 2024, at 27, https://doc.westconnect.com/Documents.aspx?NID=21108&dl=1.

192 WestConnect, "WestConnect Planning Management Committee (PMC) Meeting Notes," August 21, 2024, https://doc.westconnect.com/Documents.aspx?NID=21183&dl=1.

193 Penrod, E., "Xcel Energy draws 6.7 GW of data center requests, including from Meta and Microsoft," Utility Dive, August 5, 2024, https://www.utilitydive.com/news/xcel-energy-data-center-meta-wildfire-earnings/723239/.

194 Colorado Electric Transmission Authority, "Transmission Capacity Expansion Study for Colorado," accessed October 16, 2024, https://www.cotransmissionauthority.com/transmission-study.

195 *See* Public Service Company of New Mexico, "20-Year Transmission Planning Study," April 24, 2024, https://www.pnm.com/documents/28767612/28797910/PNM_20YearPlanStudy_2024-04-24_Slides.pdf/9f48bd5c-a874-3bad-0455-03081f35169e?t=1715188648372.

196 New Mexico Renewable Energy Transmission Authority, "Transmission Lines in New Mexico," accessed October 16, 2024, https://nmreta.com/transmission-lines/.

Other merchant lines in the southwest are being supported by DOE programs. For example, the Southline Transmission Project was awarded almost $500 million under the TFP in October 2023,[197] and DOE preliminarily identified two interregional NIETC corridors in New Mexico and Colorado that would help connect the Western and Eastern Interconnections.[198]

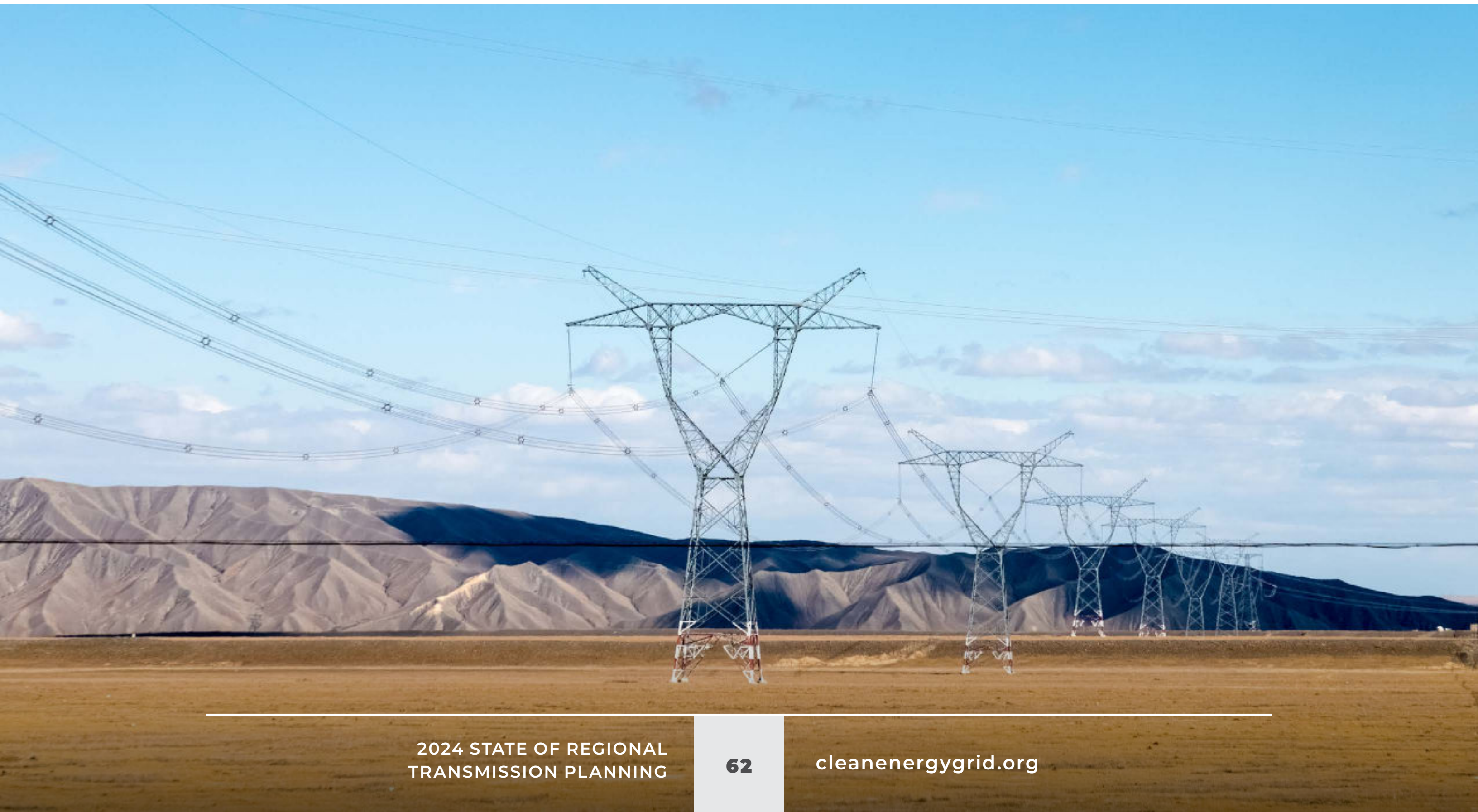
197 *See* Transmission Facilitation Program.

198 *See* NIETC Designation Process.

XII. Conclusion

In the year following the publication of the initial transmission planning and development report card, several regions have begun to implement reforms to improve their long-term transmission planning processes. While these reforms show promise, many are still in the early stages of implementation, leaving uncertainty around their ultimate impact on transmission development. For regions where reforms have yet to begin, there may be progress by 2025 as transmission planners are expected to comply with Order No. 1920's long-term planning requirements by mid-year.

Across the country, regions have made improvements to various degrees on proactive, scenario-based, multi-value transmission planning. Several regions, including CAISO and SPP, are working to integrate or harmonize transmission planning and generation interconnection processes. New York has also introduced a process to better integrate its various planning processes. Meanwhile, ISO-NE has adopted proactive, multi-value transmission planning and PJM is working on similar reforms. ERCOT, SPP, and WestConnect are incorporating extreme weather scenarios in transmission planning to better assess risks



from events like winter storms, heat waves, and hurricanes. CAISO, ERCOT, MISO, and SPP all produced historic, multi-billion dollar proposed investments in new transmission projects. Outside of the RTOs, utilities continue to drive the development of high-capacity transmission, with the most significant developments happening in the west, and Duke and TVA are poised to potentially make progress in the Southeast.

Additionally, DOE is accelerating the development of high-capacity transmission development. DOE, through the Grid Deployment Office, has launched new programs addressing the critical aspects of transmission development—planning, permitting, and paying. While this federal support represents a significant step forward, the funding available remains relatively small compared to the large-scale investments needed to meet current and future transmission demands.

Looking ahead, the full implementation of Order No. 1920 may shift the focus of regional transmission planning toward the development of multi-value, high-capacity transmission lines. This transition could mark a move away from the inefficient, incremental, just-in-time planning models that still dominate today. Such a change will drive investment in the nation's transmission infrastructure that will ultimately lower costs for consumers, improve and maintain reliability, and connect a changing resource mix to areas with rising demand.